Final Report

Mitigation of climate impacts of possible future shale gas extraction in the EU: available technologies, best practices and options for policy makers

16 January, 2014

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Executive Summary

This study is aimed at developing a list of potential policy options for minimising on-site fugitive greenhouse gas (GHG) emissions during shale gas exploration and production in the EU, and evaluating their climate, environmental and economic impacts.

The specific objectives of the study are to analyse international experiences in minimising on-site fugitive GHG emissions to identify lessons and best practices; to provide an overview of the most advanced technologies and practices that could be promoted or enforced for minimizing these emissions; to provide an overview of different policy options for a possible regulatory framework for minimizing these emissions and to analyse the climate, environmental and economic impacts of key policy options.

In Task 1, a **review of international efforts to minimise on-site fugitive GHG emissions during exploration and production of shale gas** was undertaken. Case studies were drawn from the state and federal level in the USA and at the provincial level in Canada, where commercial production of shale gas is well established. For each case study, analysis was undertaken of the type of policy mechanism; requirements for fugitive GHG emissions reductions; monitoring and reporting requirements; and approaches for public engagement and stakeholder communication.

With the caveat that large differences exist between conditions in North America and in the EU (in terms of i.a. population density, geology, road networks or topography), the study finds that the following two policies developed in the US seem to be particularly relevant for a potential EU policy framework:

- US Federal rules requiring onshore natural gas producers to report their GHG emissions, and comply with the required methods of measurement, leak detection and sampling from 2014 onwards.
- US Federal standards under which GHGs are covered indirectly through Volatile Organic Compound (VOC) emission reduction requirements. As of 1 January 2015, all producers have to use Reduced Emissions Completions (RECs) when hydraulically fracturing new gas wells; with the exception of low pressure gas wells and exploration wells. RECs involve the use of portable equipment to separate the gas from solids and liquids and produce gas that can be sold. RECs ensure that the majority of methane, which under business-as-usual (BAU) could be flared or vented to the atmosphere, is captured for later use.

In Task 2, an **assessment of key technologies and practices that can be used to mitigate fugitive GHG emissions during shale gas exploration and production** was undertaken.

The largest source of emissions is gas well venting / flaring during well completions and well workovers with hydraulic fracturing. These emissions are specific to shale gas exploration and production and could be effectively mitigated by reduced emission completions (RECs).

Other sources of emissions include equipment leaks and venting from multiple devices which are common to conventional gas exploration and production. A variety of conventional measures can effectively mitigate these emissions, as summarized in Table 5 of this report.

For each mitigation option we collected data on performance, costs and other key details, as presented in Appendix B.

To inform the impact assessment of possible additional shale gas risk management policy options, we developed assumptions on the extent to which climate mitigation measures could be assumed to be taken up under 'business as usual' (BAU) policies. The current lack of directly applicable EU legislation specifically addressing fugitive methane emissions from shale gas exploration and production and the limited extent of conventional onshore gas production in the EU makes the development of such assumptions quite difficult. As such, we drew on available US data and experience to provide indicative assumptions. The US experience has shown that under BAU the uptake of the assessed options would be relatively low despite their cost-effectiveness, as many producers would rather shift their investment capital into the drilling of new wells.

In Task 3, the **identification of potential policy options** was undertaken. Based on the findings of Tasks 1 and 2, a long list of different policy options for a possible regulatory framework for minimizing on-site fugitive GHG emissions was produced. A common set of criteria (including legal criteria, economic criteria, environmental criteria, feasibility criteria, stakeholder acceptance, flexibility, access to infrastructure and transparency) was used to identify four priority short listed policy options. The preferred options included:

- **Voluntary approach** in which industry would be encouraged to develop their own approach to minimising on-site fugitive GHG emissions. This could perhaps be through the provision of information exchange or guidance, or development of an industry standard (accompanied by EU intervention if the voluntary approach is not robust enough).
- **Revision of** listed activities in Annex 1 of the **Environmental Impact Assessment (EIA) Directive** to include shale gas activities. This would mean that proposed developments are subject to an EIA which would require providing a description of measures to avoid, reduce and, if possible, offset any significant adverse environmental effects. Climate mitigation measures, however, would not be explicitly required by the EIA.
- **Revision of** Annex 1 of the **Industrial Emissions Directive (IED)** to specifically include shale gas activities. This would require permitting of shale gas installations under this directive and achievement of a high level of environmental protection through application of best available techniques (BAT), including mitigation of fugitive emissions to air. 'BAT conclusions' would inform permit conditions and BAT would be defined in updateable 'BAT Reference Documents' (BREFs).
- Elaboration of a **specific EU framework for shale gas**. This could be in the form of a Regulation, Directive, Recommendation or Opinion. It would not necessarily be limited to fugitive emissions-specific provisions. This would allow a holistic approach to comprehensively address all key impacts in one legislative package and at the same time ensure a harmonised approach across all Member States. It could also provide for any amendments to other relevant legislation that are required to be made (e.g. IED or EIA Directive as well as other relevant environmental legislation with regards to waste, water, chemicals etc) and for monitoring requirements.

In Task 4, an **assessment of climate, environmental and economic impacts of the policy options** was undertaken, compared to a base case scenario assuming no additional policies for minimising on-site fugitive GHG emissions beyond those already in place or planned at an EU

or Member State level. For modelling purposes the two more stringent policy options (new EU framework for shale gas and amendment to IED) were grouped together (Scenario 1) and the less stringent options (amendment to EIA and voluntary approach) were grouped together (Scenario 2).

A number of steps were taken to estimate the impacts of the different policy options, as described in Section 5. These included:

- Energy modeling: development of estimates of the accessible shale gas resource base across the EU; development of supply curves to model the costs for shale gas production under different policy options; energy modeling using Enerdata's POLES model in order to model EU shale gas production and gas prices under BAU and different policy scenarios for years 2020 and 2030; and based on the supply curves and outputs from POLES, estimation of impacts of policy scenarios on EU energy consumption, sources of energy, energy prices and investment by the energy sector.
- Economic modeling: use of Cambridge Econometrics' E3ME model to estimate competitiveness and employment impacts in specific sectors.
- Emissions impacts: estimation of impacts on GHG emissions and air pollutants.

The energy and economic modeling was undertaken jointly for this project and for a related project for DG ENV "Macroeconomic Impacts of Shale Gas Extraction in the EU". Where the approaches are common to both reports, the descriptions of the work undertaken are given in the DG ENV report.

The results demonstrate that the climate mitigation policy options represented by Scenario 1 and Scenario 2 have a negligible economic impact compared to the base case, because the policies have almost no impact on energy production, energy prices and energy demand. This is due to the modest impact of the policy options on shale gas production costs - the capital costs and annual operating costs of climate mitigation measures are more than offset by the annual revenue from recovered methane. The cost-effectiveness of these measures is demonstrated in Table 12.

The climate mitigation policy options are estimated to result in reductions of EU fugitive methane emissions from shale gas exploration and production in 2020 and 2030 of 35% to 40% for Scenario 1 and 20% to 25% for Scenario 2, compared to base case emissions. These represent by far the most dominant source of GHG impacts of the policy options. Other GHG impacts include CO_2 emissions from flaring; energy related CO_2 emissions from gas extraction and production; and combustion related CO_2 emissions from downstream energy mix changes.

Fugitive methane emissions are likely to be associated with small concentrations of Hazardous Air Pollutants (HAPs) which will also be reduced by the climate mitigation policy options to a similar degree as methane. Our assessment has developed estimations of reductions in EU-wide emissions of 3 key air pollutants for which emissions factor data was available, namely benzene, toluene and hydrogen sulphide. Estimates illustrate that the more stringent policy options (Scenario 1) could lead to emissions reductions in 2020 and 2030 within the range of 35% to 40% for all three air pollutants, compared to the base case, and less stringent policy options (Scenario 2) could lead to reductions within the range of 20% to 25%.

The estimates of impacts on shale gas emissions and production costs can be affected by various sources of uncertainty. These include uncertainties in emissions factors; abatement efficiencies of mitigation measures; capital and operating costs of mitigation measures; gas

prices; uptake of measures under the base case; requirements for additional uptake of measures under policy scenarios; projections of numbers of wells and their characteristics; and scale up of emissions per well to emissions per MS. Further sources of uncertainty relate to the energy and economic modeling approaches. When comparing the differential impacts between the policy scenarios and the base case, however, uncertainties will tend to cancel out and become less important. As such, the comparative results from this analysis are considered to provide a robust basis for comparing the policy options.

1. Introduction

1.1 Objective of study

This study focuses on developing a list of potential policy options for minimising on-site fugitive GHG emissions during shale gas production and development in the EU, and evaluating their climate, environmental and economic impacts.

The specific objectives of the study – as determined in the Terms of Reference (ToR) – are as follows:

- **Analyse international experiences in minimising on-site fugitive GHG emissions during exploration and production of shale gas, identifying lessons and best regulatory practices that could be used in the EU (Task 1).**

- **Analyse shale gas exploration and production technologies and practices to provide an overview of the most advanced technologies and practices that could be promoted or enforced for minimizing on-site fugitive GHG emissions (Task 2).**

- **Develop and provide an overview of different policy options for a possible regulatory framework for minimizing on-site fugitive GHG emissions and promoting the most advanced technologies and practices of shale gas exploration and production (Task 3).** This task aims to provide an overview of the different options for a regulatory framework, and an assessment of these options based on a common set of criteria to identify 3 or 4 to assess in the next task.

- **Analyse the climate, environmental, social and economic impacts of relevant policy options (Task 4).** Various impacts, in accordance with the European Commission's guidance on impact assessment (January 2009), and associated guidance including the "Competitiveness Proofing" Toolkit, will be analysed and compared to a base case or 'business as usual' (BAU) scenario assuming no additional regulations for minimising on-site fugitive GHG emissions and promoting the most advanced technologies and practices of shale gas exploration and production beyond those already in place or planned at an EU or Member State level.

As stated in the ToR, for the purposes of this study, on-site fugitive emissions are to cover GHG emissions from:

- Intentional venting of gas for economic or safety reasons (e.g. venting during well completions, or during equipment maintenance operations;

- Leaks - both accidental and built into the equipment design (e.g. rotating seals, or open tanks);

- Incidents involving rupture of confining equipment (e.g. pressurised tanks or well isolation)

This study is to focus in particular on GHG emissions arising during the well completion phase, but other stages of shale gas exploration and exploitation with significant potential for emission reductions should also be considered.

1.2 This report

This final report sets out the findings from the study. The following sections are included:

- Section 2 sets out the findings from Task 1;
- Section 3 sets out the findings from Task 2;
- Section 4 presents the findings from Task 3;
- Section 5 presents the results from Task 4.

2. Task 1 – Analysis of international experiences in minimising on-site fugitive GHG emissions during exploration and production of shale gas

2.1 Introduction

The objective of this task was to research experiences outside the EU in minimising on-site fugitive GHG emissions during exploration and production of shale gas, and identifying lessons and best regulatory practices that could be used in the EU. Section 2.2 sets out the approach taken for this Task. Section 2.3 provides an overview of lessons learnt and best regulatory practices outside the EU.

In Task 3, relevant current and planned policies in European Member States are also explored (see Section 4.2.1).

2.2 Approach

2.2.1 Review of international experience

The first step in this task was to identify key countries and states that are considered to have the most relevant and credible regulatory and other practices for minimising on-site GHGs from shale gas exploration and production that can be used as a source of learning for the EU.

In this initial step we gathered readily available data from:

a. General and multi-national sources, including: IEA's report on Golden Rules for a Golden Age of Gas, UK Environment Agency's study on Monitoring and Control of Fugitive Methane from Unconventional Gas Operations[1], AEA's report on Climate impact of potential shale gas production in the EU.

b. In-house unconventional gas specialists, who drew on in-house knowledge, access to country-specific information sources and in-country contacts to review and supplement the collected information.

As stated in the IEA (2012) report "Golden Rules for a Golden Age of Gas" the United States is a key reference point in the unconventional gas revolution and regulatory developments at both federal and state levels will do much to define the scope and direction of similar debates in other countries.[2] Moves are underway to build on the existing regulation and practice, for example by tightening the rules on air emissions, ensuring disclosure of the composition of fracturing fluids and improving public information and co-operation among regulators. Therefore the US is certainly a key country for consideration. Furthermore, Canada is one of only a few countries outside the US where commercial production is already underway and has some interesting regulatory examples.

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[1] UK Environment Agency (2012) assessment of methods available for monitoring and controlling fugitive emissions included analysis of 5 international case studies. The report is available here: http://cdn.environment-agency.gov.uk/scho0812buwk-e-e.pdf

[2] IEA, Golden Rules for a Golden Age of Gas, p.103. http://www.slideshare.net/MarcellusDN/ieas-golden-rules-for-a-golden-age-of-gas-report

The following 10 case studies were selected for further analysis to investigate good practice in control and monitoring of fugitive emissions from unconventional gas extraction:

1. United States Federal Government – Natural Gas STAR Program;
2. United States Federal Government – New Source Performance Standard OOOO;
3. United States Federal Government – Greenhouse Gas Reporting Rule;
4. Wyoming (WY) Department of Environmental Quality- Permitting Guidance;
5. Colorado (CO) Oil and Gas Conservation Commission (COGCC) Guidance and Colorado Department of Public Health and Environment;
6. Fort Worth City, Texas (TX) – City Ordinance;
7. Utah (UT) – Greater Natural Buttes Area Gas Development Project;
8. New York (NY) – Although the state has a moratorium right now on hydraulic fracturing (fraccing), it has a comprehensive set of regulations/mitigation measures in place in case the moratorium gets lifted – these are examined in this case study.
9. British Columbia (BC), Canada – this province has the most shale gas exploration and production activity in Canada. Relevant guidelines, laws and regulations have been assessed in this case study.
10. Alberta, Canada – a new regulatory approach was put forward by the Albertan Energy Resources Conservation Board (ERCB) in December 2012[3] specifically designed to address risks from unconventional gas extraction. The proposed regulation and its requirements (which is unlikely to come into operation until 2014, and possibly not until 2015) are assessed in this case study.

In the second phase of work, information was collated on each of the 10 case studies using a data collection proforma. Literature searches were conducted to populate the proforma. The pre-filled templates were then sent to relevant stakeholders for their review and further input, including at least:

- 1 regulator per case study;
- 1 regulated company per case study;
- 1 academic / university / lawyer per case study.

The completed proformas are provided in Appendix A.

[3] http://www.ercb.ca/projects/URF/URF_DiscussionPaper_20121217.pdf

KEY FINDINGS

Table 1: Summary of findings from international case studies

Case study	Type of Policy	Requirements for fugitive GHG emissions reductions	Monitoring requirements	Notification and reporting requirements
US Federal Government – Natural Gas STAR Program	Voluntary program supported by federal agency (US EPA)	The Program encourages operators to adopt cost-effective technologies that reduce methane emissions. No requirements – all reductions are voluntary.	No monitoring requirements. However if companies adopt any emission reduction projects they are required to report the methane emission reductions associated.	If companies adopt any emission reduction projects they are required to report the methane emissions reductions associated. The US EPA maintains the results in a confidential database.
US Federal Government – New Source Performance Standard OOOO	Federal rule	Regulates VOC emission from hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and leaking components at onshore natural gas processing plants, as well as sulphur dioxide (SO_2) emissions from onshore natural gas processing plants.[4] GHGs covered indirectly through VOC emission reduction requirements. Under this rule gas venting from hydraulically fractured gas well completions is no longer allowed.	Specific monitoring methods are detailed for leak detection and repair (LDAR) and multiple emission sources including: centrifugal compressors, storage vessels and reciprocating compressor affected sources.	Rule provides a notification process in advance of impending well completion operations – the notification is a condition of permitting. Standard annual report to include all well completion records.

[4] US EPA, 40 CFR Parts 60 and 63, p. 49492 http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/html/2012-16806.htm.

Case study	Type of Policy	Requirements for fugitive GHG emissions reductions	Monitoring requirements	Notification and reporting requirements
		Producers are expected to either install combustion devices such as flaring or use RECs when hydraulically fracturing new gas wells. As of 1 January 2015, all producers are expected to use RECs; with the exception of low pressure gas wells.		
US Federal Government – Greenhouse Gas Reporting Rule Subpart W	Federal rule	No requirements for fugitive GHG minimisation. The rule merely requires certain industries to report their GHG emissions. For onshore natural gas production facilities, operators must report CO_2, CH_4 and N_20 emissions from 18 emission sources on a single well-pad.	Under Subpart W, EPA has allowed operators to use best available monitoring methods (BAMM) for well-related emissions, for specified activity data, and for leak detection and monitoring up to 2013. After 2013, operators will have to comply with the required methods of measurement, leak detection and sampling.	Annual reports to be submitted to US EPA electronically. EPA verifies the data submitted.
Wyoming (WY) Department of Environmental Quality - Permitting Guidance & Green Completions Permit Guidance	State program	GHGs covered indirectly through VOC emission reduction requirements. Best Available Control Technology (BACT) should be applied at wellsites. Capture VOC emissions at the well site during completions and recompletion activities.	Total volumes of hydrocarbon liquids and natural gas recovered from the wellbore during completion/recompletion, as well as total hydrocarbon liquids/gases recovered that were flared/vented.	Completion of Well Completions Emissions Worksheet.
Colorado (CO) Oil and Gas Conservation Commission (COGCC) Guidance and Colorado Department of	State program	Green completions reduce methane emissions directly while other measures also indirectly reduce methane N_2O and	Conditions of permit	Conditions of permit

Case study	Type of Policy	Requirements for fugitive GHG emissions reductions	Monitoring requirements	Notification and reporting requirements
Public Health and Environment		CO_2.		
Fort Worth City, Texas (TX) – Gas Drilling and Production Ordinance	State program	Provides a number of regulations to reduce GHG emissions e.g. use of RECs; no venting during fracking operations and vapour recovery from storage tanks.	Ordinance designates a Gas Inspector who enforces the Ordinance provisions.	Conditions of permit
Utah (UT) – Greater Natural Buttes Area Gas Development Project	State program	Program aimed at reducing emissions of NOx and VOCs to avoid ozone formation. GHGs covered indirectly through VOC emission reduction requirements.	Conditions	
New York State (NY) GHG Emissions Impacts Mitigation Draft Plan	State program (draft)	Requirements to reduce GHG emissions associated with flaring/venting and leaks to the extent possible by establishing GHG mitigation impacts plan.	No monitoring requirements but operator will provide GHG mitigation reports upon request.	LDAR report to be prepared annually.
British Columbia (BC), Canada – Flaring and Venting Reduction Guideline	Province regulation and guidance	Provides regulatory requirements and guidance for flaring, incinerating and venting in British Columbia from oil and gas producing wells and production facilities.	Detailed monitoring requirements are specified.	Flared and vented gas must be reported according to rules. Permit holders must maintain a log of flaring and venting events and respond to public complaints.
Alberta, Canada – New regulatory framework to deal with unconventional resources	Province regulation (draft)	Play-focused approach (as opposed to licensing of *individual* activities in relation to *individual* pools.[5])	Specific requirements have yet to be determined.	Specific requirements have yet to be determined.

[5] A play consists of several fields; each field includes a number of pools in a certain productive formation.

Case study	Type of Policy	Requirements for fugitive GHG emissions reductions	Monitoring requirements	Notification and reporting requirements
		Specific requirements have yet to be determined.		

2.2.2 Assessment of relevance for the EU

Following the development of the 10 case studies, the next step is to assess their potential relevance for the EU. Development of shale gas regulations by the EU should take into consideration the large differences that exist between conditions and settings in North America and in the EU at a number of different levels. Differences in Member State regulatory status, population, geology, road networks, topography and other factors should be considered.[6] This is done, to the extent possible, using a series of key criteria to identify similarities between the international situation and that in the EU, bearing in mind that an in-depth assessment of the local conditions in each European Member State is beyond the scope of this project. Factors to be considered in developing a regulatory framework include the following:

- Political support: Political support may range from enthusiastic to full moratoria.
- Population density: Population density plays a key role in evaluating the applicability of international practices because densely populated areas may have stricter planning controls and permitting requirements leading to tighter standards for risk reduction, air, water and land quality. Industry access is also much more restricted in urban and suburban areas.
- Mineral ownership and surface rights: Legislation in different countries differs on ownership of above ground land rights over underground resources.
- Energy transportation and processing infrastructure: Adequate gas processing and pipeline infrastructure must be in place to transport gas to the gas grid.
- Topography: A significant aspect of the economics of unconventional gas production is the ability to drill and complete a large number of wells in a given area on a relatively uniform well spacing to take advantage of economies of scale and various efficiencies.
- Resource type, play geology, and nature of gas and fluids: Different plays have individual characteristics related to drilling, fracturing, completion, and production that affect the applicability of regulations. Factors to consider include depth, reservoir thickness, rock mechanics, length of horizontal laterals, and the spatial relationship to underground sources of drinking water.

[6] Some of these differences could have a significant impact on air emissions and potential regulations, and others would likely have more impact on other aspects of development such as water quality preservation.

- Stakeholder concern: Public opposition about the impact of drilling on the community and environment may be very vocal.

For the EU, the following reports have been used as sources:

- The 'Shale Gas Revolution': Developments and Changes[7];
- World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States[8];
- Unconventional Gas: Potential Energy Market Impacts in the European Union[9].
- Golden Rules for a Golden Age of Gas?

The evaluation matrix below illustrates key differences between the EU, US and Canadian provinces.

[7] Stevens, P. (2012) The 'Shale Gas Revolution': Developments and Changes. A Chatham House Report
[8] US EIA (2011) World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States
[9] JRC (2012) Unconventional Gas: Potential Energy Market Impacts in the European Union

Table 2: Evaluation Matrix to Determine Suitability of International Practices for EU

Category	EU	US (specifically CO, WY, TX, NY states)	Alberta and British Columbia provinces, Canada
Political situation / support	- Currently political standpoints on unconventional development range at the national level from enthusiastic support in Poland to the current moratoria on hydraulic fracturing in place in France, Bulgaria, North-Rhine-Westphalia in Germany, Cantabria region of Northern Spain, Netherlands and Luxembourg.	- Strong political support and backing at the federal level - Some of the largest shale gas deposits are located in states that do not have a recent history of oil and gas production. As such, state agencies are not well positioned to deal with rapid growth in oil and gas development.[10]	- Regulations are set at provincial level with overarching national level regulations also. Political support is strongest in the western provinces of Alberta and British Columbia where resource extraction has a longer history. Unconventional gas extraction in the Eastern provinces has less political backing.
Mineral Ownership/ Sub-surface Rights	- Property rights reside with the state and landowners receive no compensation or reward. - The size of individual land holdings in European countries is smaller than in North America, which means that more landowners are involved in a project.	- Property rights in the United States make the shale gas the property of the landowner, creating a financial incentive for private owners to allow the disruptions associated with shale operations.	- Property rights reside with the state and landowners receive no compensation or reward.
Population Density	- Europe has, in general, a higher population density than almost all of the areas currently being developed in North America. - For example, the areas in which initial resources are located in the UK are densely populated regions. Average population density	- Populations in many of the relevant states (UT, CO, WY, TX) are accustomed to proximity to onshore oil and gas operations. - Low population density in many of the key shale areas. One exception	- Low population density in key shale areas - Populations in these states are used to proximity to oil and gas operations.

[10] Argonne National Laboratory (2012) Hydraulic Fracturing and Shale Gas Production: Technology, Impacts and Policy

Category	EU	US (specifically CO, WY, TX, NY states)	Alberta and British Columbia provinces, Canada
	in the UK is 383 people per km^2 (compared to 27 people per km^2 in the US).[11] - This issue is particular relevant when compared with conventional gas reserves, as shale gas resources are spread more thinly over much wider areas. - The US model of "factory drilling", where hundreds of wells are drilled across a specific play to identify a "sweet spot" is therefore unlikely to be appropriate for most European markets. Instead a target approach is more suitable, where detailed R&D takes place to identify sweet spots more accurately.	is that operators in the Barnett Shale of North Texas have worked with the city of Fort Worth to permit drilling in and around a relatively densely populated area. Considerations include noise, truck traffic, visual aspects, air emissions, impact on local housing, and other factors. All of these factors can be addressed and the operators in the Barnett play have made operational changes in these areas.	
Industry & infrastructure	- Historically, Europe has been a 'project supply market'[12] with few buyers and sellers and poor price transparency. Thus there was no "gas price" upon which to base the contract price. Transaction costs to buy and sell gas are high. - Pipeline access is based upon 'third party access' which means if the pipeline is full any gas suppliers must build their own pipeline to access markets. - Europe has a much more sparse oil and gas transportation and processing infrastructure than exists in most of the areas of the U.S.	- The US is a 'commodity supply gas market', i.e. a lot of buyers and sellers and good price transparency. Gas is easy to sell. - Pipeline access is based upon 'common carriage' so gas producers have some access to existing pipelines facilitating the economics of shale gas production. - While there are large infrastructure issues in the U.S. related to shale gas expansion, most areas had	- Canadian natural gas market has a highly liberalised structure as a result of far-reaching regulatory reforms that began in 1985. - Canada has relatively well-developed pre-existing pipeline infrastructure that has been built around historical conventional production

[11] House of Commons Energy and Climate Change Committee (2011) Shale Gas: Fifth Report of Session 2010-2012. Volume II.

[12] Historically there have been two types of gas market into which exporters could try and sell: A commodity gas supply market or a project gas supply market. In the former a large number of buyers and sellers of gas operated in a relatively transparent market. Today, only North America, the UK and perhaps Argentina (although there are significant price controls) can be described as real commodity supply markets.

Category	EU	US (specifically CO, WY, TX, NY states)	Alberta and British Columbia provinces, Canada
	that have shale gas development. Onshore Europe has relatively widely scattered and minor oil and gas production. 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). Due to the shortage of existing oil and gas infrastructure, significant midstream and pipeline infrastructure will be required at an early stage of development. - The service industry is an American-dominated oligopoly. In July 2010 there were only 34 land rigs in all of western Europe. It has been suggested that drilling a shale gas well in Poland costs three times as much as in the United States, reflecting the lack of service industry competition[13]. - Licensing acreage traditionally covers relatively small areas with strict work programmes.	sufficient capacity to handle the initial years of production, providing time to expand the capacity, which can take many years. Such infrastructure consists of gathering lines, gas processing plants, compression facilities, NGL liquids fractionation facilities, and gas and oil transmission lines. Construction and operation of these facilities is a consideration in terms of air emissions impacts as well. - Industry has been dominated by small, entrepreneurial companies, although larger companies are now getting involved - Dynamic, highly competitive service industry. At the height of operations in the Barnet Play in 2008, 199 rigs were in operation - The industry is used to license large areas for exploration with fairly vague work programme commitments, which is what is needed when dealing with shale plays.	
Access restrictions related to conservation areas	- A significant constraint in the development of European shale is the presence of large areas	- In the US, land that is protected by national park status may still be	- National parks are protected under the federal Canada National Parks

[13] Stevens, P. (2012) The 'Shale Gas Revolution': Developments and Changes. A Chatham House Report

Category	EU	US (specifically CO, WY, TX, NY states)	Alberta and British Columbia provinces, Canada
	that are set aside for natural resource conservation.	vulnerable to impacts from development of non-federal mineral rights within park boundaries on privately held mineral estates[14].	Act from all forms of industrial development including mining, forestry, oil and natural gas exploration and development, and hydro-electric development, as well as commercially extractive activities such as sport hunting.
Stakeholder / public concerns	- Opposition to the drilling of shale wells is expected to vary greatly by country and locality, but in general is expected to be much higher in much of Europe than in some parts of North America. - Onshore oil and gas operations are not common in Europe. However, shale gas operations can create significant levels of employment, which may enhance their attractiveness to local communities. - There has been widespread media coverage of the growing public backlash against shale gas development based on concerns over its impact on the environment. In Bulgaria, the decision by the government to award shale gas permits has been attacked by opposition socialists and green groups, who have started a campaign against the drilling. - At the same time, some communities in Europe are actively embracing the shale gas	- Populations in some of the states are used to proximity to oil and gas operations. However, there is very vocal stakeholder concern areas without a recent history of oil and gas development[15] and also in metropolitan areas e.g. New York state, Pennsylvania, Salt Lake City (UT), Boulder (CO) and Longmont (CO). - Much of the land in CO/UT/WY is tribal lands which presents specific concerns.	- Hydraulic fracturing has been conducted in the western provinces for over 60 years and so there is less opposition around the practice than in other areas (e.g. New Brunswick & Quebec) where the practice has less history. - Much of the land is First Nations land which presents specific concerns.

[14] http://www.marcellus.psu.edu/resources/PDFs/marcellusshalereport09.pdf.pdf

[15] Argonne National Laboratory (2012) Hydraulic Fracturing and Shale Gas Production: Technology, Impacts and Policy

Category	EU	US (specifically CO, WY, TX, NY states)	Alberta and British Columbia provinces, Canada
	potential. Poland's national gas company, Polskie Górnictwo Naftowe i Gazownictwo (PGNiG), has started the "Flame of Hope" campaign		
Resource Type, Play Geology, and Nature of Gas and Fluids	- Shale plays are, generally, smaller, deeper, have less material and have a high clay content compared to North America, making fracking relatively difficult. A key question is whether wells in Europe have sufficient gas pressure to allow application of green completion (as opposed to combustion / flaring) (see Task 2). - In Eastern Europe, outside of Poland, the shale gas potential has not been widely explored.	- Large, material plays, implying large technically recoverable resources. - The U.S. EPA has determined that well pressures below 500 pounds per square inch (about 35 Bar) reduced emissions completion 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.[16]	- Large, material plays, implying large technically recoverable resources (not as large as the U.S. though).

[16] IEA, Golden Rules for a Golden Age of Gas, p.30. http://www.slideshare.net/MarcellusDN/ieas-golden-rules-for-a-golden-age-of-gas-report

2.3 Overview of lessons learnt and best regulatory practices outside the EU

2.3.1 Types of policy mechanisms for reducing emissions

- There needs to be a balance between standard national legislation and regulation optimised for local characteristics of the shale. In the United States, individual regulations vary considerably between states. Although more localised regulations allow better optimisation to specific environmental and geological conditions, there is also value to regulation of certain areas at the federal level. In the US, this balance is accentuated by the traditional balance of state versus federal primacy in regulation setting. The U.S. federal government sets national regulations such as the New Source Performance Standards (NSPS). Each state must set regulations that at the minimum comply with the federal regulations. Rather than drafting their own legislation, most states just adopt the language of the federal regulation to their own state regulation. On the other hand, some states, such as California, choose to adopt regulations that are more stringent than the federal regulations. National regulators should consider how flexible they make regulations within their nations to allow optimal balance of regulatory simplicity and optimisation.

- The NSPS rulemaking was prompted by a lawsuit filed by environmental organisations in January 2009, alleging that EPA had missed the statutory deadlines for reviewing and updating the NSPS and NESHAP standards for the oil and gas sector.[17] Interviewees have noted that regulatory efforts were well underway on the state and local levels to respond to GHG emissions from shale gas E&P. For example, Fort Worth (TX) has required green completions on all natural gas wells since 2009 (well before NSPS came into action).

- In response to the Kyoto Protocol, the US launched the Natural Gas STAR program as a vehicle to try to cost-effectively reduce non-CO_2 GHG emissions in the oil and natural gas sector. ICF's analysis shows that the Natural Gas STAR program has been effective in reducing methane emissions, despite being a voluntary program. This is due to the cost-effective nature of the control technologies. The majority of the control technologies capture significant amounts of methane that would have been lost otherwise, with many projects paying out in the year of implementation. Natural Gas STAR program partners represent 59 percent of the U.S. natural gas industry and have allegedly reduced emissions by over 400 million metric tonnes of CO_2 equivalent since the program's inception. The program has over 115 domestic (U.S) and international partners spanning the production, gathering and boosting, transmission and the distribution sectors (although not all in shale gas). In 2010, nearly 80 percent of U.S. partners submitted an annual report detailing their efforts to reduce methane emissions from their operations. These voluntary activities consisted of nearly 100 technologies and practices and resulted in domestic emissions reductions of 38 million metric tonnes of CO_2 equivalent in 2010 alone. Furthermore, some States require proof of participation in the

[17] WRAP (2011) Analysis of States' and EPA Oil and Gas Air Emissions Control Requirements for Selected Basins in the Western United States. Available online here: http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20(01-08).pdf

program as part of permitting regulations (e.g. New York State GHG Emissions Impacts Mitigation Plan draft).

- In the Canadian province of British Columbia, a Flaring and Venting Guideline (see Appendix A for specific details) has been extremely effective in reducing flaring levels in oil and gas facilities (there has been a 36% decrease between 1996 and 2011, despite an overall increase in natural gas production by 76%). Directive 060 "Upstream Petroleum Industry Flaring, Incineration, and Venting" developed in Alberta has also been very effective and is an example of a dedicated piece of stand-alone regulatory legislation that covers most of the elements of the province's flare and vent regulatory regime.

- The *cumulative* impact of multiple wells being drilled on a single play is largely not addressed in the case studies assessed. The current approach in British Columbia and the US is based on the licensing of *individual* activities in relation to *individual* pools.[18] The Canadian province of Alberta has recently proposed a new approach to dealing with unconventional gas resources which adopts a play-by-play approach. Under this approach, regulatory solutions will be tailored to an entire "play" to achieve specific environmental, economic, and social outcomes. This is particularly relevant given the scale of unconventional resource plays gives rise to concerns about cumulative impacts.

- Geographies will have different issues/solutions depending on the geology of the shale and the particular regional characteristics—regional solutions should be sought to share knowledge among operators. For example, shale gas operations can lead to increased levels of ozone and hazardous air pollutants (HAPs) such as benzene. However air quality is highly dependent on local conditions. This is illustrated in the Colorado, Wyoming and Utah case studies which all report winter ozone exceedances. Some interviewees highlighted the needed for specific policy responses to respond to such localised effects.

2.3.2 Fugitive GHG emission reduction requirements

- The case studies presented indicate that not all of the regulations are specifically targeted at reducing GHG emissions. Instead GHGs are covered indirectly through VOC emission reduction requirements.

- The U.S. experience demonstrates that Reduced Emission Completions (RECs) can cost effectively reduce 95 per cent of methane emissions from uncontrolled well completions from hydraulically fractured wells. The New Source Performance Standards (NSPS) Subpart OOOO regulates volatile organic compound (VOC) emissions (and GHG emissions as a co-benefit) in the crude oil and natural gas sector. The use of RECs, also known as "green completions", has been prescribed for hydraulically fractured natural gas wells in some states and nationally from January 2015 onwards under the proposed NSPS. According to the NSPS Technical Support Document, the cost of compliance with RECs is net negative if the methane savings are taken into account. Flaring, required immediately under the NSPS is also an effective methane mitigation measure but results in emissions of CO2 and conventional pollutants. See

[18] A play consists of several fields; each field includes a number of pools in a certain productive formation.

"United States Federal Government – New Source Performance Standard OOOO" in Appendix A for more information on the NSPS program. Task 2 (Section 0) provides a detailed analysis of technologies to control fugitive GHG emissions.

- US EPA recently published a proposed amendment to the NSPS rule that includes consideration of the large number of storage tanks and the remoteness of many wells sites.

- The newly established NSPS OOOO for the crude oil and natural gas production source category regulates VOCs from hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and leaking components at onshore natural gas processing plants, as well as sulphur dioxide (SO_2) emissions from onshore natural gas processing plants."[19] The rules will also be effective at reducing emissions of methane and CO_2. Furthermore, the rule also sets cost-effective performance standards for: gas wells, storage vessels, certain controllers and certain compressors.

- The North American case studies indicate that there are mature and proven cost-effective technologies and practices for significantly reducing GHG emissions from shale gas exploration and production. For example, RECs that limit CH_4, VOC and HAPs (such as benzene) emissions and reduce flaring (further discussed in the following section). These technologies have been used extensively in North America both in response to regulations and economic drivers (i.e. due to value of captured methane) and should be applicable in the EU. The correct regulatory signals can ensure the appropriate use of such technologies.

- While this task presents a snapshot of current mitigation efforts in key areas in the US, the case studies presented highlight the range in outcomes from policies designed to limit emissions. For instance, while Colorado and Utah share a border, both operating in the Uinta-Piceance Basin, Utah's production-related emissions remain significantly higher than those in Colorado, according to stakeholder feedback. While the type of basin plays a part in emissions, the incongruent regulatory measures remain a key factor. Whereas Utah's measures focus on limiting ozone, Colorado has more specific measures such as green completions, limiting emissions at the wellhead.

2.3.3 Monitoring and reporting (including confidential information) requirements

- Data collection and management is critical and needs to be planned early. In the United States, operators have expressed a desire for simplification and standardisation of reporting across states to reduce compliance costs. The Greenhouse Gas Reporting Rule was enacted on October 30, 2009, in response to a congressional mandate in EPA's FY2008 appropriation (P.L. 110-161). The rule required 31 categories of sources to report their emissions of greenhouse gases to EPA annually, beginning in 2011, if the sources emit 25,000 tons or more of carbon dioxide or the equivalent amount of five

[19] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Part 63, [EPA-HQ-OAR-2010-0505; FRL-], RIN 2060-AP76 http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf, Page 17 of 588.

other greenhouse gases (methane, N_2O, SF_6, HFCs and PFCs).[20] It plays a key role in collecting accurate and timely GHG data from the oil and natural gas sector that is essential for informing future climate policy decisions. Furthermore, the emissions data collected under the rule will enable EPA to develop emission factors that are used to develop emission inventories that are in turn used to assess risks, track trends and analyse potential policies. Under subpart W, the EPA has required reporting emissions from well completions for hydraulically fractured gas wells.

- In a number of the case studies, inspections of activities were considered (by regulators) to be insufficient, particularly of small operators.

- In Alberta, reported flaring and venting volumes are made public on a regular basis. As well as demonstrating the transparency of the regulatory process, it also puts 'peers pressure' on poorly performing operators to improve their performance. Total flare and vent volumes are reported annually, with a breakdown of flaring and venting volumes by operator. Annual reporting of flare and vent volumes provides a clear measure of progress in flaring and venting reduction in the jurisdiction and creates positive pressure for continuous improvement, while the operators' statistics identify the 'champions' and the 'laggards'. The report on flaring and venting issued annually by the Alberta ERCB is a good example of such practice.

- The NSPS OOOO regulation requires annual reporting for each affected facility. Appendix A provides a summary of the gas well reporting requirements under the rule. All emission data and reporting requirements are specifically authorised by the Clean Air Act under section 114 and are not entitled to confidential treatment and shall be made available to the public.

- The US EPA has determined which data points constitute confidential business information (CBI) under the US Greenhouse Gas Reporting Rule Subpart W. Those that were determined to be CBI are shown in Table 3 below. Reporting requirements categorised under inputs to emission equations (Category 2) were collected by the EPA however a decision on whether to release this data to public has been deferred till a later date until EPA could determine whether the data elements compromise any information that gives competitors an unfair advantage over reporting companies.

Table 3: Summary of CBI data categories in Subpart W[21]

Category	Example Data Element	CBI Determination
2. Inputs to emission equations	Annual quantity of CO_2, that was recovered from each acid gas removal unit and transferred outside the facility (metric tonnes CO_2e),	Deferred

[20] James E. McCarthy, James E. McCarthy, EPA Regulations: Too Much, Too Little, or On Track?, Congressional Research Service, http://www.fas.org/sgp/crs/misc/R41561.pdf.

[21] http://www.epa.gov/ghgreporting/reporters/cbi/index.html

Category	Example Data Element	CBI Determination
	under subpart PP of this part	
4. Unit/Process 'Static' Characteristics that are not inputs to Emission	For well venting for liquids unloading: Internal casing diameter or internal tubing diameter in inches, where applicable	Some data elements are CBI and some are not CBI (Majority of data elements are deemed to be not CBI)
5. Unit/Process Operating Characteristics that are not Inputs to Emission	For all glycol dehydrators, which vent gas controls are used	Some data elements are CBI and some are not CBI (Majority of data elements are deemed to be not CBI)
8. Production/Throughput Data that are not Inputs to Emission Equations	For each centrifugal compressor with wet seals, annual throughput in million standard cubic feet.	CBI

2.3.4 Public Engagement and Stakeholder Communication

- Proactive engagement with operators in developing regulation will help the implementation of effective solutions and reduce the cost of compliance. To establish an efficient, effective regulatory environment, regulators should engage operators early to set clear directions for development. U.S. EPA conducted extensive meetings with stakeholders both prior to publishing the draft NSPS proposed rule, and then again after the proposed rule was published. These meetings included the oil and gas industry, who provided information informing how aspects of the regulation could impact the industry, and the capability of equipment operating in the industry to comply with contemplated emissions criteria; thus to avoid unintended consequences. The NSPS rule is a national standard with built in flexibility, recognising the technical difficulties.

- US EPA also conducted meetings with State environmental regulators when drafting the proposed NSPS. State regulators are active on the ground and as a result several have extensive knowledge of the oil and gas operations.

- US EPA conducted meetings with environmental organisations during the NSPS rule development that provided an important public interest perspective. EPA also held meetings with the public that were well attended.

- Transparency builds trust among stakeholders and is strongly correlated to the level of public acceptance. Operators should endeavour to meet information and knowledge sharing requests from relevant stakeholder groups.

- The case studies reveal that in areas without a recent history of oil and gas development (e.g. New York state and New Brunswick province in Canada), the public tends to be

more sceptical of new development and the risks involved. This scepticism can manifest itself in public opposition to development that can be costly for operators to overcome. Therefore, early engagement is crucial.

2.4 Overview of recommendations for the EU

- Public opposition tends to be greater in areas without a recent history of oil and gas development. Credible scientific research is needed to improve quantification of the actual versus perceived environmental risks and to improve public trust. Adequate communication, coordination, and planning involving operators, regulators and stakeholders prior to development can be important to help address public concerns and ensure that best practices are being used to mitigate impacts and risks.

- Any regulatory measures introduced in the EU should contain strong monitoring, reporting and enforcement measures. Monitoring should be implemented during all relevant phases of shale gas activities (e.g. after the hydraulic fracturing stage, during production operations). Monitoring should cover the shale gas site and its direct area of influence. Reporting emissions to air should be carried out during all phases of the shale gas activities. Furthermore, leaks and other venting often occur episodically; ongoing data logs will identify such episodes, which will assist inspectors and operators in identifying habitually problematic areas that would not otherwise be obvious during routine inspection or operations. The use of automated data collection can reduce requirements for on-site supervision.

- As far as possible data should be openly disclosed to relevant stakeholders.

- Any regulatory measures should also include provisions that operators must follow proper equipment usage instructions. Improper use, such as exceeding pressure specifications of drilling equipment, can result in unnecessary emissions.

- Regulations often include provisions under which flaring and/or venting are allowed under certain “upset” conditions. However, upset conditions are sometimes vaguely defined and left to the operator to determine. These conditions must be clearly defined to limit situations under which unnecessary emissions can be avoided.

- The EU should consider a play-based approach in any regulatory efforts to deal with climate impacts from unconventional gas exploration and production (as is currently being developed in Alberta). Dealing with the cumulative impacts of shale gas operations is noted as an important element in successful public engagement.[22]

- Any regulatory approach should seek to be flexible so that it can account for technical operational characteristics and variations across different shale gas plays. NSPS sought to set a minimum standard that could be achieved by the majority of operators. For example, geological factors can directly affect greenhouse gas capture; for instance, a formation characterised by low pressure[23] will not economically facilitate

[22] Argonne National Laboratory (2012) Hydraulic Fracturing and Shale Gas Production: Technology, Impacts and Policy

[23] Defined as 500 pounds per square inch absolute (psia), or 3.45 mega pascals (MPa). http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf, p. 2-17.

use of a REC, as well pressure (a function of the geology) decreases as a REC is applied. However, a minimum level of pressure is needed for a REC to be effective. In cases where the well pressure is too low to facilitate a REC, flowback gas could be flared, or in some cases, vented.

- Based on the unique characteristics of the different shale gas plays, a mitigation option that works for a certain shale gas play might not necessarily work for another. Any regulatory approach should strive to balance national and local standard national legislation and regulation optimised for local characteristics of the shale. Coordination across regulatory agencies within a region is also important.

- Geographies will have different issues/solutions depending on the geology of the shale and the particular regional characteristics—regional solutions should be sought to share knowledge among operators. Local characteristics are key to framing the fugitive emissions management options available to operators.

3. Task 2 – Analysis of shale gas exploration and production technologies and practices for minimising on-site fugitive GHG emissions

3.1 Introduction

In this task, the key technologies and practices that can be used to mitigate shale gas production fugitive GHG emissions have been assessed. As shale gas processes are developing and changing rapidly so this task addresses both current technologies and those under development, as well as identifying any recent changes that have occurred since some of the recent studies in circulation.

3.2 Approach

3.2.1 Prioritisation of emission sources

In the first step of this task, an assessment of the priority sources of shale gas production fugitive emissions was made. In order to do so, several emission sources associated with a typical shale gas operation were examined. Only vented (by design) and fugitive (unintentional leaks) GHG emissions were considered - combusted GHG emissions were not considered in this analysis. Table 4 summarises the results of this analysis.

The table provides representative U.S. CH_4 and CO_2 emission factors (EFs), representative U.S. activity factors (AFs) and the annualized (average annual lifetime) GHG (CH_4 + CO_2) emissions for a U.S. natural gas well for each of the emission sources. The representative EFs and AFs shown in the table below are derived from the 2012 U.S. EPA Inventory of Methane and Carbon Dioxide Emissions from Natural Gas Systems. Other sources such as the 2012 API/ANGA study and HPDI data were used to supplement the inventory data. An average well lifetime of 10 years was assumed. A methane content of 78.8% and a CO_2 content of 4.8% were assumed when estimating the EFs.

The table below shows two scenarios, one in which the flowback gas from well completions is vented, and one in which the flowback gas from well completions is flared.[24] Table 4 clearly shows that the top GHG emission source is associated with the flowback gas from well completions with hydraulic fracturing regardless of whether the gas is vented or flared. When vented, the flowback gas from completions accounted for 47% of the well GHG lifetime emissions. On the other hand when flared, the flowback gas from well completions accounted for 30% of the well GHG lifetime emissions. Given that well completions occur once over the lifetime of a well, a longer well lifetime would decrease the impact (as a percentage of total emissions) of well completions, while a shorter well lifetime would increase their impact. Well workovers for hydraulically fractured wells have a high emission factor, however; only 1% of shale gas wells are assumed to require a well workover and as a result, the total emissions from this source are relatively small. The majority of GHG emissions for a shale gas well come from well completions and well workovers. The remaining emissions come from pieces of equipment that can be found with a conventional non-associated natural gas well.

[24] In 2011, 66% of U.S. shale gas wells that reported their emissions under Subpart W vented the flowback gas from their well completions, while 34%flared the flowback gas from their well completions.

It should be noted that the hydraulic fracturing of shale gas wells requires numerous vehicles on a well pad, and the combustion emission of these engines is a significant source of GHG emissions compared to the venting and fugitive emissions. US EPAs subpart W requires the reporting of the combustion emissions from these vehicles and other equipment.

Sources highlighted in green are not found in conventional operations, i.e. they are unique to shale gas operations.

Table 4: Identification of top sources of shale gas production fugitive and vented emissions

Vented and Fugitive GHG Emission Sources	Typical CH_4 Emission Factor[25]	Typical CO_2 Emission Factor[26]	Activity Factor per Shale Gas Well	Average Annual GHG Emissions Per Source per U.S. Natural Gas Well (CO_2 Tonne Equivalent)	Source Emissions as a Percentage of the Total Emissions Assuming Venting of Well Completion Emissions	Source Emissions as a Percentage of the Total Emissions Assuming Flaring of Well Completion Emissions
Gas well venting during well completions with hydraulic fracturing[27]	204.8 thousand Cubic Metre (TCM) / completion (7,230 Mcf/ completion)	12.5 TCM/ completion (440 Mcf/ completion)	1 completion per shale gas well drilled.	194	47.2%	0%
Flare stack emissions from well completions	4.1 TCM/ completion (145 Mcf/completion)	735.7 TCM/ completion (25,979 Mcf/completion)	34% of shale gas wells flare the flowback gas from well completions	48	0%	29.9%
Gas well venting during well workovers with hydraulic fracturing.[28]	204.8 Thousand Cubic Meter (TCM) / completion (7,230 Mcf/ workover)	12.5 TCM/ completion (440 Mcf/ completion)	1% of all shale gas wells undergo a well workover.	3	0.5%	0.6%

[25] Assumed a methane content of 78.8% for all emission sources.

[26] Assumed a CO_2 content of 4.8% for all emission sources.

[27] This emission occurs once over the lifetime of a shale gas well.

[28] Assuming a wellworkover occurs in the first year. In reality, only 1% of hydraulically fractured wells undergo a well workover over their lifetime.

Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).	1.1m^3/hour (39 scf/hour)	0.07 m^3/hour (2.4 scf/hour)	Table W-1A and Tale W-1B to Subpart W of Part 98	140	22.5%	29.8%
Natural gas driven pneumatic pump venting.[29]	28.1m^3/million m^3 (992 scf/MMscf)	1.7 m^3/million m^3 (60 scf/MMscf)	89.1 % of dehydrator output.	87	13.9%	18.4%
Well venting for liquids unloading (LU).	6.7 TCM/year/LU Event (235 Mcfy/ LU event)	0.4 TCM/year/LU Event (14 Mcfy/ LU event)	41.30% of shale gas wells were assumed to required liquids unloading.	40	6.3%	8.4%
Dehydrator vents.	7.8m^3/ million m^3 (275.6 scf/ MMscf)	(0.5m^3/ million m^3) (16.8 scf/ MMscf)	See attached spreadsheet	27	4.3%	5.8%
Natural gas pneumatic device venting.	9.8m^3/ day/ device (345 scfd/device)	0.6m^3/ day/ device 21 scfd/device	0.486 Pneumatic Devices/gas well	25	4.0%	5.3%

[29] This value is based on an average well production of 18,700m^3 per day. A lower production flow rate would decrease the impact of this source.

Storage tanks vented emissions from produced hydrocarbons.	0.6m^3/ bbl[30] (21.87 scf/ bbl)	0.04m^3/ bbl (1.5 scf/ bbl)	843 bbl per year	4	0.7%	1.0%
Reciprocating compressor rod packing venting.	7.6m^3/ day/ compressor (267.75 scfd/ comp)	0.5m^3/ day/ compressor (16.3 scfd/ comp)	0.087 compressors/ non-associated gas well	3	0.6%	0.7%

[30] US oil barrel. 1 barrel = 159 litres.

A description for the top 10 GHG sources listed in the table above is given below:

1. Gas well venting during well completions with hydraulic fracturing (specific to unconventional wells).

During a gas well completion with hydraulic fracturing, fracture fluid (primarily water and sand) are injected into the well and reservoir at high enough pressure to fracture the reservoir rock. Subsequently, natural gas from the fractured reservoir pushes the fractured fluid out of the well bore (i.e., flowback). The flowback is a mixture of natural gas, condensate, and saturated fracture fluids and is not suitable for gathering pipelines. Operators need to remove the majority of the fracture fluids to prepare the well for connection to a gathering pipeline. The flowback is typically flown into a pit where the gas is vented and the fracture fluids are collected. Typically, it takes about 3 to 10 days to perform a well completion following a hydraulic fracture (i.e. in the absence of a control device, gas is vented for 3 to 10 days).[31]

Experiences that companies have shared show that gas well drilling in the U.S. has shifted dramatically to unconventional gas requiring hydraulic fracturing. This drilling completion technology has substantially higher methane emissions than conventional well completion. Furthermore, ICF has learned that production companies generally vent the back-flow gas rather than flare it unless required by state regulations.

2. Gas well venting during well workovers with hydraulic fracturing (specific to unconventional wells).

There are many types of workover practices, most of which have small or no emissions. However, periodically it becomes economical to re-fracture unconventional wells to enhance gas production. This is virtually the same procedure as described above for new well completions wells. Well workovers have similar emissions to well completions.

3. Natural gas pneumatic device venting (found with conventional wells).

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 1.4 billion cubic metres per year in the production sector in the U.S., are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

4. Well venting for liquids unloading (slightly different for shale gas wells).

In mature gas wells, the accumulation of fluids in the well tubing can impede and eventually halt gas production. Gas flow is maintained by removing accumulated fluids through the use of a beam pump or remedial treatments, such as swabbing, soaping, or venting the well to the atmospheric (referred to as “blowing down” the well). Blowing wells to the atmosphere is very inefficient in removing accumulated liquids and result in substantial methane emissions.

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[31] Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, Lessons Learned EPA. http://epa.gov/gasstar/documents/reduced_emissions_completions.pdf

5. **Natural gas driven pneumatic pump venting (found with conventional wells).**

Circulation pumps found in glycol dehydration units and chemical injection pumps are used to inject methanol and other chemicals into wells and flow lines. These pumps are often powered by pressurized natural gas at remote locations and as a result, they vent methane to the atmosphere during operation.[32]

6. **Storage tanks vented emissions from produced hydrocarbons (found with conventional wells).**

Crude oil storage tanks are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. In addition, the condensate liquids contained in produced gas that are captured by a mist eliminator filter/ coalescer ahead of the first compressor station in transmission pipelines are often directed to a storage tank as well. During storage, light hydrocarbons dissolved in the crude oil or condensate—including methane and other volatile organic compounds (VOC), natural gas liquids (NGLs), hazardous air pollutants (HAP), and some inert gases—vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. As the liquid level in the tank fluctuates, these vapors are often vented to the atmosphere.

7. **Reciprocating compressor rod packing venting (found with conventional wells).**

All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and amount of wear on the rings and rod shaft. A new packing system, properly aligned and fitted, may lose approximately 0.31 to 0.34 standard cubic metres per hour. As the system ages, however, leak rates will increase from wear on the packing rings and piston rod. Emissions as high as 25.5 standard cubic metres per hour on one compressor rod have been reported.

8. **Dehydrator vents (found with conventional wells).**

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. The amount of methane absorbed and vented is directly proportional to the TEG circulation rate.

9. **Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources** (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps) (found with conventional wells)

10. **Centrifugal compressor venting (not very common in the U.S. production segment).**

[32] EPA Lessons Learned, Convert Natural Gas-Drive Chemical Pumps, http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf

Centrifugal compressors are widely used in production and transmission of natural gas. Seals on the rotating shafts prevent the high-pressure natural gas from escaping the compressor casing. Traditionally, these seals used high pressure oil as a barrier against escaping gas. Methane emissions from wet seals typically range from 1.1 to 5.7 standard cubic metres per minute. Most of these emissions occur when the circulating oil is stripped of the gas it absorbs at the high-pressure seal face. Dry seals, which use high-pressure gas to seal the compressor, emit less natural gas (up to 0.17 standard cubic metre per minute for a two seal system), have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance.

3.2.2 Identification and assessment of relevant mitigation options

The second step of this task was to identify the mitigation options available applicable to the priority emission sources. This was based on in-house unconventional gas specialists with extensive knowledge of technologies and best practices for reducing/minimising on-site GHG emissions through its work in support of the US EPA's Natural Gas STAR Program as well as the New Source Performance Standards (NSPS).

The most cost-effective mitigation option for each of the 10 GHG emission sources identified in the previous step was identified. It is noted that emissions from well completions with hydraulic fracturing and emissions from well workovers with hydraulic fracturing share the same mitigation technology (RECs). The 10 selected technologies/practices were prioritised according to their impact on overall GHG emission reductions and are listed in Table 5 below:

Table 5: GHG shale gas mitigation technologies, organised according to lifetime GHG emission reductions potential.

Rank	Emission Source	Mitigation technology	Specific to Unconventional Gas Wells?
1	Gas well venting/flaring during well completions with hydraulic fracturing. Gas well venting during well workovers with hydraulic fracturing.	Reduced Emission Completions (RECs)	Yes
2	Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading	Conducting Directed Inspection and Maintenance	No

Rank	Emission Source	Mitigation technology	Specific to Unconventional Gas Wells?
	arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).		
3	Natural gas driven pneumatic pump venting	Convert Natural Gas-Driven Chemical Pumps to Instrument Air Driven or to Electrical Pumps	No
4	Well venting for liquids unloading	Installing Plunger Lifts Systems in Gas Wells	No
5	Dehydrator vents	Optimise Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators	No
6	Natural gas pneumatic device venting	Convert High-bleed Pneumatic Devices to Low-bleed	No
7	Reciprocating compressor rod packing venting	Rod Packing Replacement in Reciprocating Compressors	No
8	Storage tanks vented emissions from produced hydrocarbons	Installing Vapour Recovery Units (VRUs) on Storage Tanks	No
9	Centrifugal compressor venting	Replacing Wet Seals with Dry Seals in Centrifugal Compressors	No

Rank	Emission Source	Mitigation technology	Specific to Unconventional Gas Wells?
9[33]	Centrifugal compressor venting	Installing a Wet Seal Degassing Recovery System for Centrifugal Compressors	No

For each of these mitigation options, a template was used to collect data on:

- Performance - typical average abatement efficiency (and key factors affecting this), typical average methane recovery efficiency (and factors affecting this) and energy/resource consumption
- Costs - capital and operating cost per well and unit production, revenue per well and per unit production and factors affecting these.
- Other key details – reliability, applicability, stage of development, limitations and expected future developments.

The completed templates with information collected on each mitigation option are presented in Appendix B.

3.2.3 Extent to which mitigation options could be assumed to be taken up under BAU policies

The final part of this Chapter considers the extent to which the climate mitigation technologies identified in Section 3.2.2 could be assumed to be taken up under 'business as usual' (BAU) policies by shale gas extraction and production facilities. This is to inform the development of a base case scenario in Section 5, without additional shale gas risk management policies.

The current lack of directly applicable EU legislation specifically addressing fugitive methane emissions from shale gas extraction and production in this area, for example prescriptions of best available techniques (BAT) under the Industrial Emissions Directive (IED), makes the development of such assumptions quite difficult.

Furthermore, whilst it is noted that nine out of the ten techniques in Table 5 are regarded as not specific to unconventional gas wells, the extent of conventional onshore gas production in the

[33] Replacing wet seals in centrifugal compressors and installing wet seal degassing recovery systems are alternatives. In other words, one technology would take the market share of the other. NB 9 and 9 are mutually exclusive.

EU is quite limited, in comparison to offshore gas production, which means that the current onshore gas sector can provide only a limited evidence base for the BAU uptake of such techniques.

As such, we have drawn on available US data and experience to provide assumptions on BAU uptake rates of abatement techniques for fugitive methane emissions from shale gas extraction and production that would be applicable without specific climate mitigation policies.

Under this scenario, the adoption rate of the mitigation technologies will be a function of the strength of the economic and environmental drivers that apply to the relevant facilities. Producers often have multiple investment opportunities and limited capital to invest in revenue improvement (i.e. drilling new wells), expense reduction and environmental projects. These mitigation technologies are often considered by companies as expense reduction or environmental projects. Whilst payback periods may be relatively short, and environmental benefits would be achieved, revenue improvement projects may be preferred instead. Based on expert experience with these mitigation technologies in the US, our working assumptions of the indicative BAU adoption rate are shown in the following table. See Appendix F for further details.

Table 6 Working assumptions of the indicative BAU adoption rate

Technology	Assumed indicative BAU adoption rate %
Reduced emissions completions	50%
Directed Leak Inspection and Measurement	10%
Convert natural gas driven chemical pumps	10%
Install flash tank separators in dehydrators	10%
Install plunger lift systems in gas wells	15%
Convert high bleed pneumatic devices	40%
Rod packing replacement in reciprocating compressors	40%
Install vapor recovery units on storage tanks	10%
Replace wet seals in centrifugal compressors	40%
Install wet seal degassing recovering system in centrifugal compressors	0%

4. Task 3 – Overview of policy options for minimising on-site fugitive GHG emissions

4.1 Introduction

The objective of this task is to develop and provide an overview of different policy options for a possible regulatory framework for minimising/reducing on-site fugitive GHG emissions and promoting the most advanced technologies and practices of shale gas exploration and production. It builds on the findings of Tasks 1 and 2 taking into consideration the assessment of international experience in regulatory practices, production technologies and practices for minimising on-site fugitive GHG emissions.

In this chapter a longlist of policy options for a possible regulatory framework is presented. From this longlist, a shortlist of 3 or 4 policy options is selected at the end of this Chapter.

4.2 Approach

4.2.1 Review of current/planned regulation in Member States

In this first step, a review was made of current and planned regulatory or other measures regarding the control of fugitive emissions from shale gas extraction and production at the national level. It is noted that this step has involved close collaboration with Milieu who have been contracted by DG ENV to investigate regulatory practices in 8 Member States (BG, DK, DE, ES, LT, PL, RO and the UK).[34] MS competent authorities in these countries were surveyed with numerous questions, one of which was relevant to this study:

- What are the requirements (if any) to prevent gas leakage and air pollution applicable to unconventional gas projects?

The draft outputs of the Milieu study were provided to ICF for the purposes of this study. From this assessment it was possible to assess which MSs have developed or are planning to develop regulatory measures to control fugitive emissions.

Box 1 Milieu Study for DG ENV (Draft) Findings on Venting and Flaring in 8 Member States

Venting and Flaring in the selected Member States

Bulgaria

Resulting from the analysis of the legal framework, there are no special regulations on gas leakage and air pollution connected with the well requirements. The operator is obliged to undertake measures to prevent gas leakage and air pollution under the requirements of the general environmental legislation (Environmental Protection Act, Clean Air Act) as well as under the measures provided in the EIA decision.

Denmark

In Denmark, on-site operations need to be granted prior approval from relevant authorities. In total 7 primary permits need

[34] The Term of Reference for the study states: 'The objective of this service contract is to identify and assess environment- and health-related regulatory provisions applicable to unconventional gas in 8 selected EU Member States: Bulgaria, Denmark, Germany, Spain, Lithuania, Poland, Romania and United Kingdom.

to be obtained. Drilling work may not commence before a drilling permit is obtained. A detailed drilling program for the work must be presented to the Danish Energy Agency (DEA) to obtain a permit including information on the drilling rig, safety aspects, daily report economic information. The obligation is included in the drilling permit and as a condition in the approval of the development plan.

Germany
Provisions directly applicable to venting and flaring can be found in the technical regulations and standards of the German Industry Association Oil and Gas Extraction (Wirtschaftsverband Erdöl- und Erdgasgewinnung')[35], as well as in the Technical Instructions on Air Quality Control. ('Technische Anleitung Luft, Technische Anleitung zur Reinhaltung der Luft'). The provisions are specific and detailed enough to also deal with the venting and flaring of gases evolving from fracturing activities.

Lithuania
Paragraph 22.3 of the Rules on preparation of projects for exploitation of hydrocarbon resources[36] requires that the project document includes measures against hydrocarbon spills in the environment and open blow-out. The Rules do not specify what kind of measures must be as they depend on the techniques and technologies used. However, under Article 14(1) of the Underground Law, relevant authorities may require submission of additional information on the technology as well as strengthen the environmental protection and safety measures. The EIA procedure should also be considered as an important measure preventing unexpected gas leakage and air pollution during exploitation phase.

The new draft law requires drilling projects to include technical description of the proposed activities including measures against leakage of gas and measures ensuring environmental protection and safety at work.

Poland
According to the representative of the State Mining Authority, in the extraction phase, all gas leakages are liquidated. If the liquidation is impossible, the entire well is to be liquidated. Moreover, the general requirements of the Environmental Protection Law Act regarding air protection apply (Arts. 85 - 96a of the Environmental Protection Law Act). Furthermore, where required, the EIA decision sets the environmental requirements to be applied during the operational phase of the projects. It may include conditions on air pollution.

Romania
According to the Petroleum Law Norms, an investor cannot start exploration until all the legal requirements regarding the discharge of waste waters and the burning of associated gases that are not subject to exploitation are duly in place. Through experimental exploitation, the beneficiary of a Petroleum Agreement is required to collect gas samples for burning and has the obligation to present a report to NMRA regarding the obtained results.[37]

No gas leakages are allowed for the petroleum installations. The beneficiary must ensure that all equipment is checked according to the standards elaborated by the State Inspection authority and any leakage must be notified to NMRA.

According to Chevron, while flaring could be required for temporary management of gases during preliminary tests, in practice, the NMRA does not allow flaring of gas for unlimited duration in order to avoid emissions and the waste of resources. The company explains that during the environmental authorisation process, the potential gas emissions are assessed and venting the natural gas would only be allowed for emergency situations, while the gas should be normally used or burned to reduce its greenhouse impact. Companies in the sector may also apply internal safety rules to reduce the incidence and consequences of such issues.

[35] For an overview of the technical regulations and standards see WEG, "TechnischeRegeln- Ueberblick", available at: http://www.erdoel-erdgas.de/article/articleview/130/1/93/.

[36] Angliavandenilių išteklių naudojimo projekto rengimo taisyklės, http://www3.lrs.lt/pls/inter3/dokpaieska.showdoc_l?p_id=269183&p_query=&p_tr2=2

[37] Technical instructions issued by NMRA in 2006 regarding experimental exploration.

Spain

The decisions by the Ministry of environment requiring an EIA prior to granting authorization of works within investigation permits do not refer to specific legislation regarding requirements for air pollution or avoidance of gas leakage. However, they request an evaluation of the potential emissions to the atmosphere from motors, venting, fugitive or diffuse emissions as well as the evaluation of emissions from methane or other greenhouse gases.

The decisions require the operator to submit a description of all infrastructures needed for the exploration and exploitation activity, including transport, waste management and any auxiliary infrastructure. Operators are required to present the control mechanism established during the whole process including testing of the integrity of the pipelines, the integrity of the well, cement and casting of well and pipelines as well as sealing tests to be carried out during drilling, fracturing and at the end of the activities. The control mechanisms should be carried out regularly by independent actors guaranteeing the integrity and absence of breaches. Operators should also submit information on the technique used for fracturing and the control mechanisms during fracturing process.

Annex IV of the Law 34/2007 of air quality and protection of the atmosphere recognises the activities of fossil fuel extraction and hydrocarbon production as well as the torches of oil and gas extraction plants as potentially polluting activities of the air quality. Operators of installations where those activities are carried out are required under Article 7 to respect the emission limit values and perform emission controls. Under Article 13, those activities are subject to permits establishing the emission limit values, provisions to reduce long distance pollution, systems for emissions control, measurement methodology, frequency and procedures for evaluating measurements; the measures relating to the operating conditions in situations other than normal which may affect the environment, such as commissioning, leaks, malfunctions, temporary stoppages or decommissioning and the period for which the authorisation is granted.

Inspection measures are defined and carried out by the Autonomous Communities. Any infringement of the authorisation regime under Article 13 is considered a very serious infraction which will be sanctioned with fines between 200,001 to 2,000,000 Euros, permanent or temporary closure or termination or suspension of the authorisation.

United Kingdom

Schedule 3, paragraph 21 of the Petroleum (Production) (Landward Areas) Regulations 1995 makes provision for the avoidance of harmful methods of working. The model clause states that the Licensee shall not flare any gas from the licensed area or use gas for the purpose of creating or increasing the pressure by means of which petroleum is obtained from that area, except with the consent in writing of DECC and in accordance with the conditions, if any, of the consent. Before deciding to withhold consent or to grant it subject to conditions, DECC shall give the Licensee an opportunity of making representations in writing about the technical and financial factors which the Licensee considers are relevant in connection with the case and shall consider any such representations made by the Licensee.

Consent shall not be required for any flaring which, in consequence of an event which the Licensee did not foresee in time to deal with it otherwise than by flaring, is necessary in order to remove or reduce the risk or injury to persons in the vicinity of the well in question or to maintain a flow of petroleum from that or any other well. In the latter scenario, the Licensee shall inform DECC and shall, in the case of flaring to maintain a flow of petroleum, stop the flaring upon being directed by the DECC to stop it.

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 will not normally consent to venting unless flaring is not technically possible. In the Ministerial Statement made by the Secretary of State for Energy and Climate Change on Exploration for Shale Gas, it is stated that, like with the venting of methane, which is already required to be reduced to the minimum technically possible, the flaring of methane will also be required to be reduced to the economic minimum. However, concern has been expressed by one NGO interviewed, regarding the meaning of the term ‘economic minimum’ which is rather vague, and may vary depending on fluctuating gas prices.

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. The Borehole Sites and Operations Regulations 1995 and the Borehole Sites and Operations Regulations (Northern Ireland)

1995 (BSOR Regulations) prohibit commencement of a borehole operation unless the operator ensures that a health and safety document has been prepared, which must include 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. 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.
Local authorities are also responsible under the Environmental Protection Act 1990 for inspecting sites for odour and noise associated with the venting or flaring of gas. Local authorities also have a statutory duty under the Air Quality Standards Regulations 2007 to monitor emissions to ensure they do not breach local air quality standards.

Based on the above assessment, the following Member States were found to be of particular interest:

- Denmark,
- Germany,
- Poland, and the
- UK.

Relevant competent authorities were contacted in these Member States with follow-up surveys. These are presented in Appendix C.

KEY FINDINGS

Shale gas exploration in the EU is still in its infancy and, as a result, the regulatory position for some aspects of onshore unconventional gas are still being reviewed and developed at the national level.

On the basis of available literature and surveys to competent authorities, the Member States assessed in this study have so far relied upon existing mining legislation on hydrocarbons and relevant EU requirements to control GHG emissions from shale gas exploration and exploitation. No Member State has been found to set specific requirements to control GHG emissions from shale gas activities. They instead rely on the application of their mining and environmental legislation.

Most countries refer to the legislation on air quality establishing emission limit values (ELVs) to control venting from the exploitation of unconventional gas. Most of them do not allow this activity unless there is a permit and/or in case of emergencies. In general the regulation of these activities is not clear and some Member States refer to the Integrated Pollution and Prevention Control (IPPC) Directive (now Industrial Emissions Directive (IED)). However the type of activities covered by the installations classified under the IED do not really cover unconventional gas extraction and could only be applicable if the installations are considered similar to the installations for the production of gas (refineries).

The UK is arguably one of the most active Member States in terms of dealing with the restriction/control of fugitive emissions from shale gas. As reported in the AEA (2012) report there are a number of regulatory regimes in place that indirectly control methane emissions from unconventional gas extraction. 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 August 2012, the UK Environment Agency (EA) undertook a study to investigate Monitoring and control of fugitive methane from unconventional gas operations[38].

In February 2013 the UK Onshore Operators Group (UKOOG), a body representing the UK onshore oil and gas industry, released the Onshore Shale Gas Well Guidelines.[39] Section 10 of these Guidelines specifically addresses minimising fugitive emissions (see Box 2).

Box 2 UKOOG (2013) Onshore Shale Gas Well Guidelines

Section 10 Minimising Fugitive Emissions

Operators should plan and then implement controls in order to minimise all emissions.

Operators should be committed to eliminating all unnecessary flaring and venting of gas and to implementing best practices from the early design stages of the development and by endeavouring to improve on these during the subsequent operational phases.

Emphasis should be placed on "green completions" whereby best practice during the flow-back period is to use a "reduced emissions completion" in which hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling. However this approach will not always be practicable at the exploration/appraisal stage of a development where separation and flaring of natural gas should be the preferred option, minimising venting of hydrocarbons wherever practicable.

Operators should make available and disclose emissions data in line with best practice and any regulatory reporting requirements (e.g. flaring would be in accordance with DECC approvals etc.).

In Denmark, the VVM Procedure (Vurderinger af Virkninger på Miljøet – Environmental Impact Assessment) must be completed before starting any activities subjected by the EU directive on VVM/EIA. The purpose of a VVM is to ensure an assessment of the environmental impact as the basis for the decision to grant or refuse permission to activities that potentially can addect the environment significantly. The actual VVM procedure is performed by the relevant municipality. Public involvement is an important part of decision-making. This ensures that the municipality has a good basis for making environmentally informed decisions. Drilling for gas is covered by Annex 2 which means a screening of the project is necessary in order for the municipality to determine whether the project requires a full VVM, or whether a screening is sufficient.

The Subsoil Act requires all hydrocarbon installations to have closed system to prevent venting, which is forbidden in Denmark. The obligation is included in the drilling permit and as a

[38] http://cdn.environment-agency.gov.uk/scho0812buwk-e-e.pdf

[39] http://www.ukoog.org.uk/elements/pdfs/ShaleGasWellGuidelines.pdf

condition in the approval of the development plan. The legislation also stets strong restriction to flaring. Maximum amount of flaring are sets based on the production target of the installations and on the best available techniques. Flaring activities are monitored on a daily and monthly basis and enquiries are led if the allowed amounts are trespasses without reasons (e.g. security reasons associated with specific stages of the exploitation process).See Appendix C for further details.

Furthermore, the French national legislation also goes further than the EIA Directive as all drilling works for mining exploration and exploitation of more than 100 metres depth is subject to a compulsory EIA.

4.2.2 Trans-boundary shale plays

Outside of Poland, the shale gas potential of Eastern Europe has not been widely explored. The gas-bearing shales of Western Europe are currently being actively explored and evaluated. However, available information (e.g. IEA, 2011) indicates that there are a number of potentially prospective trans-boundary basins including:

- Scandinavian Alum Shale: covering areas of Norway, Sweden and Denmark;
- North Sea-German basin: covering areas of Germany Belgium and the Netherlands;
- Pannonian-Transylvanian Basin in Hungary and Romania;
- Carpathian-Balknian in Southern Romania and Bulgaria.

In respect of the regulation of shale gas exploration and production, it is possible that different Member States will have differing approaches to implementation of EU legislation and to implementation of any relevant domestic legislation. Commercial entities in the EU are accustomed to dealing with different legislative regimes in different Member States. Increased levels of harmonisation of legislation are likely to reduce undesired outcomes in this area. The extent to which relevant legislation is or could be harmonised across the EU is discussed in policy options 8 and 10. A further complication arises where a shale play and/or shale exploration and production activities cross national boundaries. It is noted that the approach taken to carbon capture and storage is analogous. The CCS Directive provides that:

"*In cases of transboundary transport of CO_2, transboundary storage sites or transboundary storage complexes, the competent authorities of the Member States concerned shall jointly meet the requirements of this Directive and of other relevant Community legislation*."

In the event that specific shale gas legislation is introduced, a similar approach could be adopted with respect to transboundary shale gas plays. In any event, operators will be required to comply with the provisions of legislation in the jurisdiction where any regulated activity is taking place. This would include legislation with respect to, for example, planning applications and the application of relevant environmental law. In the absence of legislation which outlines the approach to be taken in the case of overlapping legislation, all applicable legislation will be required to be complied with.

4.2.3 Review of existing EU legislation

Following our review of existing EU legislation applicable to shale gas activities, the following EU legislation has been identified as the key directives for the regulation of fugitive GHG emissions:

- EU Emissions Trading Directive (2003/87/EC, as amended);
- Industrial Emissions Directive (2010/75/EC); and
- Environmental Impact Assessment (EIA) Directive (97/11/EC)
- Mining Waste Directive 2006/21/EC

We have identified the provisions of the legislation set out above that may be applicable to fugitive GHG emissions from shale gas activities. This includes any monitoring, reporting and verification requirements, as well sanctions for non-compliance. We have provided suggested amendments to the existing legislation to provide more appropriate regulation of the shale gas industry. This builds and elaborates on the findings of the study conducted by AEA (2012) on "Climate impact of potential shale gas production in the EU" for DG CLIMA.

Our analysis is summarized in the following table.

Table 7 Review of existing EU legislation

Relevant legislation	Overall scope	Type (Mandatory / Voluntary)	Details of requirements related to fugitive GHG minimisation		Monitoring requirements	Notification, reporting and verification requirements	Compliance enforcement / sanctions	Derogations to the legislation	Links to other policies	What amendments would be required to make this applicable to shale gas?
			Direct	Indirect						
EU Emissions Trading (ETS) Directive (2003/87/EC, as amended)	Applies to emissions from activities listed in Annex I. Annex I activities include the generic activity of combustion of fuels in installations with a total rated thermal input exceeding 20 MW ("Combustion Activities"). They also include a number of specific activities which are not relevant to shale gas, including in respect of production of metals, cement, pulp and paper, aviation, etc.	Mandatory for installations engaging in an Annex I activity: - To hold a GHG emissions permit and comply with the provisions of such permit; - To monitor, have verified and report their GHG emissions ; and - To surrender emissions allowances equal in quantity to the number of tonnes of carbon dioxide equivalent that they emit.	Shale gas production activities are not specifically regulated under Annex I (nor are more general oil and gas production activities). As such, a shale gas production facility would only fall within the scope of the Directive if it satisfied the criteria in respect of Combustion Activities, which is often unlikely to be the case. When the total rated thermal input of an installation is account will be taken of all elements of the installation including boilers, burners and flares.	Combustion Activities under the EU ETS Directive regulate a broad range of emissions, including in respect of the combustion of gas. The EU ETS potentially dis-incentivizes the production of shale gas by way of imposing a carbon price on activities which involve the combustion of gas (not specifically shale gas). This is particularly relevant to the power generation sector. To the extent that the combustion of gas (including shale gas) is disincentived in comparison with the use of other sources of energy generation, the EU ETS has an indirect impact on fugitive GHG minimization	Detailed monitoring requirements are set out in separate legislation relating to the EU ETS Directive (the "MRV Regulation". Monitoring and reporting of emissions is required to be complete and cover all process and combustion emissions from all emission sources and source streams belonging to activities listed in Annex I to the EU ETS Directive, and of all greenhouse gases specified in relation to those activities . A monitoring plan is required to be developed and approved. Different monitoring requirements apply for different emissions / installations.	Emissions monitoring is subject to verification, the process of which should include consideration of the monitoring report and of monitoring during the preceding year. It should address the reliability, credibility and accuracy of monitoring systems and the reported data and information relating to emissions. Reported emissions may only be validated if reliable and credible data and information allow the emissions to be determined with a high degree of certainty.	Any operator who does not surrender sufficient allowances by 30 April of each year to cover its emissions during the preceding year will be held liable for the payment of an excess emissions penalty. The penalty is EUR 100 (index linked) for each tonne of carbon dioxide equivalent emitted for which the operator has not surrendered allowances. Operators must surrender allowances in respect of their emissions despite having paid any penalty.	Key derogations include: - Member States may exclude certain low-emitting and small capacity installations. Measures have been implemented to grant free allowances in the event of carbon leakage (displacement of regulated emissions to other jurisdictions. In limited circumstances, free allowances can be granted to power generation facilities.	There are specific provisions which ensure that there is coordination between EU ETS-regulated installations and IPPC-regulated installations (see separate table in respect of IPPC). Carbon capture and storage installations which are regulated under the CCS Directive (2009/31/EC) are included in the scope of the EU ETS. The EU ETS Directive is a key element of the EU's 20/20/20 climate and energy package.	Annex I could be amended to specifically regulate shale gas production facilities (or all oil and gas production facilities). Issues that would need to be further considered include: - Whether or not shale gas production facilities can, as a technical matter, comply with the EU ETS' stringent monitoring, reporting and verification requirements, in order to ensure that the EU ETS' cap retains its integrity. - What threshold for the inclusion of shale gas production would apply. - The regulated entity to which the obligation would apply (e.g. every well head, aggregation of well heads, aggregation of shale gas operators?). - That only fugitive emissions were regulated, so as to prevent double counting of emissions that would be regulated under the EU ETS in respect of the downstream combustion of gas produced at the facility.
Industrial Emissions Directive (IED) (2010/75/EC)	*Applies to activities listed in Annex I. Annex I does not explicitly refer to unconventional hydrocarbon exploration and exploitation activities However, it does cover activities related to combustion capacity (thermal input < 50 MW) and waste as set out below.* *Section 5.1 Annex I –Disposal / recovery of hazardous waste (capacity < 10 tonnes/day) involving several types of activities (e.g. surface impoundment, oil re-refining; physio-chemical treatment).* *Section 5.2 Annex I - Disposal or recovery of waste in waste incineration plants or in waste co-incineration plants:* *(a) for non-hazardous waste with a capacity exceeding 3 tonnes per hour;* *(b) for hazardous waste with a capacity exceeding 10 tonnes per day.* *Section 5.5 Annex I -Temporary*	Mandatory for operators of Annex I activities to obtain a permit from the relevant national authorities and comply with the provisions of such permit. The environmental impacts of activities (e.g. pollution caused, generation of waste, energy efficiency, and emission to air) must be taken into consideration when setting the permit conditions. The permit conditions (e.g. emission limit values (**ELVs**)) must be based on the Best Available Techniques (**BAT**) (Article 3(10)).	Permits must include measures on ELVs for polluting substances listed in Annex II (and other polluting substances if emitted in significant quantities). Annex III lists the criteria for determining BAT.	Member States must implement a system of environmental inspections to assess environmental effects. (Article 23) Where an Environmental Quality Standard (**EQS**) requires stricter conditions than those achieved by BAT additional measures shall be included in the permit. (Article 18)	Monitoring requirements are based on the conclusions on monitoring as described in the BAT conclusions. Frequency of the periodic monitoring is determined by the competent authority in permits or in general binding rules. Periodic monitoring should be carried out at least every 5 years for groundwater and 10 years for soil. (Article 16)	Operators to compile a baseline report to establish the environmental quality of the site at the start and end of operations. Other reporting requirements will be stipulated in the permit and this will include an obligation to provide annual emission monitoring data to enable the competent authority to verify compliance with the permit.	Member States need measures so the operator informs the competent authority immediately if an incident significantly affects the environment of in the event of a permit breach; the operator limits the environmental consequence and prevents further incidents. (Article 7 & 8) If the breach of permit poses immediate danger to human health / significant adverse effect on the environment, the operation of the installation may be suspended. (Article 8) Member States to determine penalties applicable to infringement of national provisions. Penalties to	Member States may register (and not require a permit) installations using organic solvents. The competent authority may in specific cases set less strict ELVs. (Article 15(4)). Competent authority may grant temporary derogations from the emissions requirements for the testing and use of emerging techniques for a maximum period of 9 months. For activities listed in Annex I Member States may choose not to impose energy efficiency 44inimizing44 in respect of combustion units or other units emitting carbon dioxide on the site. (Article 9(2))	Environmental Liability Directive 2004/35/EC EIA Directive 85/337/EEC (Articles 5,6,7,9) EU ETS Directive 2003/87/EC Groundwater Directive 2006/118/EC Waste Framework Directive 2008/98/EC	Clarify whether a permit is required under the IED; in particular establish provisions to ensure a permit covers the complete process on the site. Under the IED a permit would be required if (part of) the installation is for the disposal or recovery of hazardous waste. The composition of hydraulic fracturing fluids used is commercially sensitive and can differ between sites, therefore it is not possible to confirm whether in every situation they would be deemed hazardous. If an IED permit is required then BAT applies. However there are no BAT reference documents for the sector yet. Clarify whether emission limit value measures would apply to methane contained within flow back from shale gas exploration and exploitation activities.

Relevant legislation	Overall scope	Type (Mandatory / Voluntary)	Details of requirements related to fugitive GHG minimisation		Monitoring requirements	Notification, reporting and verification requirements	Compliance enforcement / sanctions	Derogations to the legislation	Links to other policies	What amendments would be required to make this applicable to shale gas?
			Direct	Indirect						
	storage of hazardous wastes total capacity <50 tonnes. – *Section 5.6 Annex I – Underground storage of hazardous waste with total capacity < 50 tonnes.* *Hazardous waste is defined in Annex III of the Waste Framework Directive. US studies suggest chemicals used for hydraulic fracturing (including methane) are hazardous.*						be effective, proportionate and dissuasive. (Article 79) ELVs for air to be regarded as being complied with if none of the daily average values exceeds any of the ELVs (Annex VI (Part 8))			Add methane to list of polluting substances under Annex II.
Environmental Impact Assessment (EIA) Directive (97/11/EC)	*Applies to public and private projects likely to have significant effects on the environment (Article 1(1).)* *EIA mandatory on projects set out in Annex I and there are discretionary powers for Member States to require an EIA for projects in Annex II.* *No specific mention of unconventional hydrocarbon or shale gas activities.*	Mandatory & Discretionary Mandatory EIA required for projects in Annex I – includes extraction of petroleum and natural gas for commercial purposes where the amount extracted exceeds 500,000m3 per day. Discretionary EIA for projects listed in Annex II - includes deep drillings / surface industrial installations for the extraction of natural gas and surface storage of natural gas.	N/A	EIA 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.	Member States to ensure that developers supply certain information (e.g. estimated air emissions and significant environmental impacts). Directive requires competent authorities to consider information supplied which should include measures to avoid/reduce/remedy significant adverse side effects. For full EIA, developers will need to supply certain information (e.g. description of the direct/indirect, secondary, cumulative, short, medium and long-term, permanent / temporary, positive / negative effects of the project). (Article 5(1)) Article 5(2) enables developers to request the competent authority to provide an opinion on the information to be supplied.	If a project is likely to have a significant effect on the environment in another Member State then such Member State must be informed of the project and information on the nature of the decision to be taken. (Article 7) Member States to inform the Commission of any criteria and/or thresholds adopted for Annex II projects. (Article 12(2))	N/A	Member States may (in exceptional cases) exempt a specific project in whole (or part) from the provisions of the EIA Directive and inform the Commission before doing so. (Article 2(4))	Member States may provide for a single procedure in order to fulfill the requirements of the Directive and the requirements of Directive 2008/1/EC (integrated pollution prevention and control). (Article 2(3))	Shale gas extraction activities may not fall under Annex I due to the activity not reaching the 500,000m3/day gas extraction threshold. Therefore consider adding shale gas activities to Annex I or lowering the existing threshold value for projects. Annex II projects – Member States have the discretion to decide which project should have an EIA and approaches may differ between Member States and whether or not an EIA is required. Therefore risks may not be adequately addressed at an EU level. In any event Annex II only currently covers "extraction" and this therefore does not cover exploration activities. Therefore exploration activities currently do not require an EIA. This would need to be addressed.
Mining Waste Directive	*The Mining Waste Directive applies to waste derived from all extractive industries including shale gas. The Directive lays down risk-focused provisions covering planning, licensing, operation, closure and after-care of waste facilities. Operators must develop a waste management plan and use BAT.*	Mandatory. Member States are required to ensure that extractive waste is properly managed and that operators take measures to prevent adverse effects on the environment and human health. Operators must apply BAT. Operators are required to draw up a waste management plan. Waste facilities cannot operate unless a permit is granted	Gaseous emissions are excluded from the definition of waste under the Directive and therefore the management of these gaseous emissions from shale gas exploration and production would not be covered by measures under the Mining Waste Directive.	The Directive requires that competent authorities ensure that operators have taken adequate measures to prevent or reduce dust and gas emissions. This could be taken to include prevention or reduction of GHG emissions from shale gas exploration and production.	Competent authorities are required to inspect waste facilities and to require operators to keep records available for inspection. Waste management plans must be put in place and must include monitoring procedures. Waste management plans are to be reviewed and monitored by Member States. Waste permits will include monitoring requirements.	Member States are required to report to the Commission on implementation of the Directive every three years and to provide certain information to the Commission annually	N/A	No relevant derogations	Waste Framework Directive 2008/98/EC	The definition of "waste" could be amended to include gaseous emissions. However it is noted that this is likely to be complicated and not proportionate. The Commission could develop a non-binding reference document (BREF) covering BAT for management of waste (including fugitive GHG emissions) from shale gas exploration and production activities. However, a similar but more holistically applied approach could be achieved by regulating shale gas exploration and production under the Industrial Emissions Directive (see above).

4.2.4 Formulation of policy options

The next step is to develop a long list of policy options to respond to the climate impacts of shale gas exploration and production. The information collated throughout the preceding tasks and other sources has been used to develop the long list. In particular, it takes into consideration the recommendations from the international case studies observed in Task 1.

We have identified a number of ways in which the EU could respond to the potential climate impacts of shale gas E&P in Europe:

- No EU-level intervention;
- Non-legislative EU intervention:
    - Facilitate information exchange;
    - Production of guidance on best practices;
    - Facilitate a voluntary program with environmental organisations and energy companies;
    - Establish GHG emissions reporting framework;
    - Clarify the application of existing EU legislation through guidance;
    - Accelerate the take-up of abatement techniques through financial incentives / market based mechanisms.
- Legislative EU intervention:
    - Adapt individual pieces of existing EU legislation;
    - Develop specific EU framework for unconventional fossil fuels.

The table below elaborates each of these options below and provides a brief evaluation of each option.

Table 8 Suggested Policy Options

Policy option	Type	Method of achieving emission reductions beyond BAU policies	Potential for reducing emissions	Pros	Cons
1) No EU-level intervention	Non-legislative	The EU could choose not to issue any legislation or guidance (or pursue any of the other policy responses set out below) in respect of minimising on-site fugitive GHG emissions. Any further emissions controls would be dependent on potential actions by **MS** and/ or industry and environmental organisations e.g. in establishing their own controls for the sector if they wished.	Depends on action taken by industry/MSs.	Allows MS and/or industry and environmental organisations to develop their own legislation/guidelines if considered appropriate. For example, the UK Onshore Operators Group has produced Guidelines for UK Well Operators on Onshore Shale Gas Wells (which contain a short section on Minimising Fugitive Emissions at page 31)[40]. It is noted, however, that EU action does not preclude MS/industry-led activity. Provides significant regulatory flexibility to MS and ability to adapt to individual MS circumstances and local conditions. Certain States in the US took action in advance of any Federal-level action. For example, Fort Worth (TX) has required RECs on all natural gas wells since 2009 (see Task 1).	Likely to lead to an inconsistent approach across different MS. Some MS may issue legislation, others may implement guidance, and some may choose not to specifically address this issue at all. There would be no additional enforcement power at EU level other than the threat of potential future legislation. Even if MS guidance / legislation was implemented, it might be wrongly applied / interpreted at MS level and there would be little the EU could do to prevent this. Lack of harmonized regulatory approaches at EU level can create distortions of competitiveness and competition. Several MS have signaled that they are waiting for EU-level activity on this, as they do not have the expertise on shale gas themselves.
2) EU level information exchange	Non-legislative	Formal information exchange procedures (such as Working Group meetings) could be initiated at EU level in a systematic way to promote consistent and harmonised techniques in respect of minimising on-site fugitive GHG emissions. The procedures could include just MS competent authorities' representatives and/or representatives from industry and/or civil society. By focusing on cost-effectiveness, the information exchange could encourage operators to take additional action.	Low-medium	As for policy option 1 above. Although the EU would have no mandatory powers in place to enforce the outcome of such information exchanges, such exchanges can still be used by MS to discuss common issues and gain support and advice from others. This approach will not increase the regulatory burden on individual MS and could be a good basis for the promotion of future legislation/ guidance at a MS or EU level. Mitigation technologies for the different GHG emissions sources are known and proven (see Task 2). As such there is a clear framework for discussion of how best to regulate the issue that could be discussed at such exchanges.	As for policy option 1 above. Information sharing will not necessarily lead to concrete outcomes such as legislation. There may be potential data protection and confidentiality issues and therefore participants may not freely exchange information.
3) EU level guidance on best practices (options 2 and 3 are not mutually exclusive)	Non-legislative	Guidance on best practice could result in a BREF-type document in respect of minimising on-site fugitive GHG emissions. This would provide information on the techniques and processes that should be used in the sector, current emission and consumption levels, techniques to consider in the determination of the best available techniques (**BAT**) and emerging techniques. Flaring/venting guidelines could be produced. This approach would also be consistent with Directive 2006/21/EEC 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 , which provides that "the competent authority shall ensure that the operator has taken adequate measures to prevent re reduce dust and gas emissions." Further, operators are required to take all measures necessary to prevent or reduce adverse effects on the environment, based on BAT. A non-binding BREF-type document could take account of these requirements.	Low-medium	As for policy option 1, though such guidance may encourage a more consistent EU-wide approach to guidance/legislation. We note again that mitigation technologies for the different GHG emissions sources are known and proven (see Task 2). As such there is a clear framework for discussion of what such guidance could entail. May encourage innovation depending on how equipment suppliers respond.	As for policy option 1 above, though with a reduced likelihood of inconsistency of approach by different MS. Best practice guidance would not have the same legislative standing as formal BREFs (see further below). A process would need to be implemented for development/ adoption of the Guidance. This could be time-consuming (and may potentially be even more complex than following the formal EU legislation process, depending on how the process was managed and stakeholder buy-in).
4) Promote EU level, industry-led voluntary approach to minimising on-site fugitive GHG emissions	Non-legislative	Commercial entities in the shale gas sector could be encouraged to develop their own approach to minimising on-site fugitive GHG emissions. This could encompass information exchange and/or guidance and/or monitoring and/or technical / emissions performance standards (as discussed further above). The Commission could be prescriptive about the issues that it would expect to see covered by such an approach and which entities would be involved in the	Uncertain	This is likely to be the most flexible approach and, depending on industry buy-in, could be developed rapidly. For example, the Centre for Sustainable Shale Development (CSSD)[42], is an independent organisation, launched in March 2013 which supports sustainable shale E&P through performance standards and 3rd-party certification standards. The CSSD has developed 15	It may be difficult for the Commission to encourage this without resorting to the threat of implementing legislation if such approach does not materialise / is not robust enough. Industry may not set best practice, and are unlikely to require / encourage uptake of measures that will add to production costs.

[40] http://www.ukoog.org.uk/elements/pdfs/ShaleGasWellGuidelines.pdf

[42] http://sustainableshale.org/

Policy option	Type	Method of achieving emission reductions beyond BAU policies	Potential for reducing emissions	Pros	Cons
		development of the approach (including potentially both members of the Commission and civil society). The EC could introduce an intervention sub-option. For instance, the key industry players establish a strict voluntary agreement based on industry standards. If industry complies, then it continues as a voluntary agreement. However it becomes a mandatory standard imposed by the EC if the rules are broken. This approach could be quicker than amending primary legislation. The process of the Commission adopting voluntary criteria is consistent with existing EU legislation in the low-carbon field. For example, the Renewable Energy Directive[41] provides that the Commission may adopt voluntary sustainability criteria for biomass and biofuels. The Commission has done so. Details of the adopted standards are available at: http://ec.europa.eu/energy/renewables/biofuels/sustainability_schemes_en.htm. The Commission adopting standards for the production of shale gas would be analogous to this approach.		initial performance standards for operators that are protective of air quality, water resources and climate.[43] Some industry-level cooperation in Europe is already taking place. Gas Shales in Europe (GASH) is the first European interdisciplinary shale gas research initiative. The project, which started in 2009 with the first phase to run for three years, is sponsored by Statoil, ExxonMobil, Gas de France SUEZ, Wintershall, Vermillion, Marathon Oil, Total, Repsol, Schlumberger and Bayerngas. Note that the US Natural Gas STAR Program is a voluntary program that has been wholly funded by the federal agency (the US EPA). The Program encourages operators to adopt cost-effective technologies that reduce methane emissions. Further information is provided in Task 1.	Industry may be unwilling / unable to share information with competitors. It may be difficult for the EU to be involved in the process.
5) Create a "name and shame" or "star rating" system of "compliance"	Non-legislative	It may be possible to increase the uptake / implementation of voluntary responses discussed above by implementing a mechanism for public disclosure of compliance. Entities that have / have not complied with certain levels of performance could be disclosed on a public website. Different levels of performance could be demonstrated by achieving different rating bands. Performance could be assessed by the entities that have adopted relevant guidance or by external verifiers.	Low-medium	This may increase the external pressure to comply with best practice and encourage voluntary take-up. It may increase the transparency of compliance with voluntary standards.	A soft measure of this type is likely to be more subjective and less effective than a mandatory compliance regime.
6) Establish a GHG emissions reporting framework in relation to minimising on-site fugitive GHG emissions from shale gas exploration and production	Legislative or Non-legislative (depending on whether reporting would be mandatory or voluntary)	The AEA (2012) report recommends the implementation of an extensive, managed programme of measurement and data analysis to develop a robust evidence base upon which to develop regulatory mechanisms and policy measures. The report recommends that "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, (e.g. fugitive methane emissions from well completions and well workovers)." The reporting frame work could: - Assist in harmonising MS inventory reporting and promoting good practice; - Promote research within Europe to support MS development of data and reporting for shale gas exploration and production to ensure consistent, comparable, accurate and transparent GHG reporting; - Use Working Group meetings (such as WG1 for inventories) to promote systematic harmonisation of methods across MS. The EU could consider the development of regulatory reporting specific to the oil and gas sector in order to provide the most accurate and detailed source data for national inventory compilers to work with. 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 could build upon good practice. Monitoring data can be validated in one of two ways: 1) Specify what calculation methodologies operators must use to	Low	May create a better informed basis for future regulation of on-site fugitive GHG emissions We note that the US Federal Greenhouse Gas Reporting Rule Subpart W (Petroleum and Natural Gas Systems) requires industries to report their GHG emissions. The goal is to better understand where the emissions are coming from. The ultimate goal is to use the data to help inform policy, business and regulator decisions. The EPA introduced in its new GHG reporting rule a provision that requires reporting emissions from well completions from hydraulically fractured gas wells. Monitoring data submitted by companies is verified by the US EPA using a set of tool which flags if there are any inconsistencies/ anomalies. Mandatory reporting may: - Lead to better reporting levels than a voluntary approach and create greater consistency of approach; - Help to create a level playing field across the EU and reduce the ability of entities not to report information because of commercial sensitivity / because it would be expensive or burdensome to compile the information. Voluntary reporting may offer a more flexible approach and be easier to implement than mandatory reporting. Reporting could be used as a first step before any other policies were implemented (i.e. as per the approach to GHG regulation in the maritime sector)[44].	There would be no requirement for fugitive GHG minimisation. If implemented alone, monitoring would not lead to increased uptake of best practice in respect of fugitive GHG minimisation. Given the short duration of the well completion emissions, by the time reported emissions are verified and published it may be too late to take any significant action on those emissions. Mandatory reporting: If legislation was required this could be more burdensome to implement than a voluntary system. In the US, under subpart W the US EPA has allowed operators to use BAMM for well-related emissions, for specified activity data, and for leak detection and monitoring up to 2013 to ease burden on operators. After 2013, operators have to comply with the required methods of measurement, leak detection and sampling. Voluntary reporting: Entities may be unwilling to disclose all information because of commercial sensitivity / because it would be expensive or burdensome to compile the information and therefore undermine the reporting process.

[41] Directive 2009/28/EC

[43] http://037186e.netsolhost.com/site/wp-content/uploads/2013/03/CSSD-Performance-Standards-3-27-GPX.pdf

[44] http://ec.europa.eu/clima/policies/transport/shipping/index_en.htm "The European Commission is currently considering possible European action in 2013 to introduce monitoring, reporting and verification of greenhouse gas emissions from maritime transport as a first step towards measures to reduce these emissions."

Policy option	Type	Method of achieving emission reductions beyond BAU policies	Potential for reducing emissions	Pros	Cons
		estimate emissions and once data is submitted the central government agency can run validation/verification checks (as per the US Greenhouse Gas Reporting Rule); alternatively 2) Companies could be required to have their monitoring data verified by a 3rd party auditor (e.g. Alberta, Canada and California). Note: this places additional burden and cost on the operators.			
7) Encourage / recommend MSs to go beyond existing EU legislation	Non-legislative	Some existing EU legislation is already directly or indirectly relevant to minimising on-site fugitive GHG emissions or could be revised relatively easily to provide for their application to shale gas facilities (see options 8a-e below). As MS are able to implement requirements that are more onerous than EU legislation, MS could be encouraged to transpose EU law into national legislation a way that would expressly include shale gas facilities under, for example, the IED/ EIA Directive. The EU could promote this approach by publishing guidance on how it would like MS to regulate shale gas facilities. For example by requiring that an EIA is always required and describing what factors should be taken into account (France, Denmark and Poland). A guidance note on the application for the EIA Directive to projects related to the exploration and exploitation of unconventional hydrocarbon was published in December 2011. [45] Member States could be encouraged to amend national legislation to introduce flaring and venting regulations to: 5) i) to limit flaring to cases where there are concerns about safety, ii) to completely forbid venting of all shale gas wells, in an effort to reduce the fugitive methane emissions and VOCs linked to shale gas.	Low-medium	Potentially a quicker way to develop legislation in the sector than via EU wide legislation. Policy development work can be focused on those MSs with most interest in developing shale gas resources.	It may be difficult to get MS to implement tighter legislation in a particular way or a timely fashion without any EU legislative basis. This approach is likely to leave regulatory "gaps" that would need to be closed by other policy responses, for example with respect to reporting requirements.
8) Adapt individual pieces of existing EU legislation	Legislative	6 options are identified (a-e below).	Medium-high		
8a) Specific inclusion of shale gas production installations in Annex I of the EU ETS Directive	Legislative	Inclusion of shale gas production installations as a specifically regulated installation under the EU ETS. Monitoring, reporting and verification of GHG emissions from the shale gas production facility would be required. GHG allowances would be required to be surrendered. Obligation to surrender allowances together with the current EU ETS excess emissions penalty.	Given the current carbon price, effectiveness of the EU ETS would be limited.	If technically possible to implement this would be a market-driven approach subject to external verification and legally binding compliance.	As fugitive emissions are unlikely to occur on a regular basis at the same well head, an appropriate mechanism would need to be put in place to include such "one off" events within a legislative regime that contemplates ongoing emissions by operators Monitoring and verifying emissions is likely to be technically challenging and relatively expensive on a €/t basis. On its own, this response is unlikely to lead to best practice being adopted. If any free allocation was to be provided it could be costly to develop suitable approaches (e.g. GHG emissions benchmarks)
8b) Specific inclusion of shale gas activities in Annex 1 of the IED	Legislative	Specific inclusion of shale gas activities (irrespective of thresholds) in Annex 1 so that any shale gas operation is specifically regulated under the IED. Inclusion in Annex 1 would lead shale gas installations to be covered by the requirements of Chapter 2. A further sub-option would be to include a separate new chapter for shale gas facilities to bring more specific requirements. Shale gas activities and emission limit values would be subject to BAT Monitoring requirements, would be set out in the permit and based on BAT conclusions (of BAT Associated Emission Levels (AELs)).		Environmental impacts from the shale gas activities would be regulated under a permit. Detailed information on the shale gas facility, its releases to the environment and their environmental impact would be made available to the public. Public consultation is built into the permitting requirements under the IED. Well established approach to controlling emissions, as introduced by IPPC Directive and further tightened up	Permitting requirements for all sizes of shale gas operation may be perceived as very onerous. The development of a sector-specific BREF may be time consuming and agreement on BAT conclusions may be difficult.

[45] http://ec.europa.eu/environment/integration/energy/pdf/guidance_note.pdf

Policy option	Type	Method of achieving emission reductions beyond BAU policies	Potential for reducing emissions	Pros	Cons
				and harmonized at EU level under the IED. Enforcement / sanctions would be determined by existing MS enforcement / sanctions for IED. Development of a shale gas sector specific BREF. BAT-AELs would be determined based on a detailed assessment of EU operators and worldwide suppliers. The BREF document would be updated at a pre-determined frequency.	
8c) Specific inclusion of shale gas activities in Annex 1 of the EIA Directive	Legislative	Inclusion of any shale gas activities so that any proposed exploratory or commercial development is subject to a mandatory EIA.		Environmental impacts from the shale gas activities would be identified and considered in the EIA process and techniques considered for mitigation of any identified impacts. Potential monitoring or further investigations to be specified in planning consents. Detailed information on shale gas facilities and their emissions and environmental impacts would be made available to the public. Public consultation is part of the EIA process.	There may not be specific inclusion in the EIA of GHG emission impacts and mitigation.
8d) Lowering the flow rate threshold from wells in Annex 1 of the EIA Directive	Legislative	To be determined. Lowering the flow rate threshold from a well so it is more likely to include single exploratory wells.		There is more potential for a shale gas well to be included in Annex 1 and therefore require a mandatory EIA. See comments at 8(c) above.	Not all shale gas developments would be covered by the provision.
8e) Specific inclusion of shale gas exploration activities in Annex 2 of the EIA Directive	Legislative	Inclusion of shale gas exploration activities so that the proposed development is potentially subject to an EIA.		Ensure at EU level that exploratory developments are covered by the EIA Directive and therefore subject to consideration at MS level.	This approach still allows for MS discretion as to whether an EIA is required. Therefore, potential MS inconsistency of approach.
8f) Modify the definition of waste under the Mining Waste Directive	Legislative	Modify the definition of "waste" under the Mining Waste Directive to include gaseous substances (including fugitive GHGs from shale gas exploration and production) in order to ensure that the provisions of the Mining Waste Directive are applicable to waste from shale gas exploration and production		Though other wastes from shale gas exploration and production will be regulated by the Mining Waste Directive this approach would extend such regulation to include fugitive emissions of GHGs from shale gas exploration and production	It would be technically difficult to amend the definition of "waste" in an appropriate manner. A similar and more holistic approach would be achieved by the regulation of shale gas exploration and production activities under the Industrial Emissions Directive
9) Accelerate the take-up of abatement techniques through financial incentives (such as a subsidy)	Legislative	The EU could require MS to implement incentives in respect of the promotion of minimisation of on-site fugitive GHG emissions from shale gas. Such incentives could take the form of: - Grants in order to subsidise the implementation of certain kinds of technology; - A certificate-based (similar to a renewables portfolio obligation) / "feed-in tariff type" scheme linked to emissions saved. The aim would be to incentivise operators to implement best practice. A potential source of funding could include EU ETS auction revenue.	Medium	Financial incentives are likely to lead to the implementation of best practice where they compensate for additional expenditure.	Direct grants are unlikely to be desirable unless the relevant technologies are particularly innovative. Any certificate-based / feed-in tariff type model is likely to be difficult to implement. Operators may benefit from surplus profit if capital costs are covered by funding and if no consideration is given to revenue from extra sales gas.
10) Develop specific EU framework for unconventional fossil fuels	Legislative	Legislation would make any necessary amendments to existing legislation, for example in respect of the EU ETS Directive, IED and EIA Directive (see above). It could also provide for other elements of the policies discussed above, for example monitoring requirements or the creation of an information exchange platform. Scope not necessarily limited to fugitive emissions-specific provisions, but could also include any other requirements in relation to shale gas regulation, including in respect of specific shale-gas permitting, waste, water usage, seismicity, or health and safety regimes. The CCS Directive is a model for this legislative approach. With regards to controlling fugitive GHG emissions, we envisage that a new piece of legislation would do one of two things. It would either enforce: 1) The use of specific abatement techniques (make the use of completion	High	This would allow a holistic approach to be taken to legislation and could also encompass voluntary approaches. Ensures a harmonized approach across countries. Comprehensively addresses all key impacts in one legislative package. The EU could adopt a play-based approach as per the province of Alberta in Canada (see Task 1 case study) which is still under development, but deals with the cumulative impacts of shale gas operations. However, it is noted that any inconsistencies with the operator-based approach generally adopted in EU legislation would need to be carefully considered. See Section 4.2.2. Some oil companies may desire common pan-European	This is likely to be the most burdensome approach as it will involve the formal legislative process, including amendments to existing legislation, which may be resisted.

Policy option	Type	Method of achieving emission reductions beyond BAU policies	Potential for reducing emissions	Pros	Cons
		combustion devices (green completions) mandatory; for all shale gas wells in the EU), or 2) The achievement of certain emission levels (performance standards)[46] from different emission sources: • Gas well completions & workovers • Pneumatic controllers • Equipment leaks • Reciprocating compressors • Storage vessels • Dehydrator vents. Any legislation would also set out: • Monitoring, reporting and verification requirements. • Emission control requirements • Enforcement sanctions. Please see following text under 4.2.5 on options for developing a new EU framework.		regulation to make it easier for them to operate across borders. Without consistent EU-wide legislation, compliance with different legislation in a number of Member States may increase the administrative and operational burdens of shale gas exploration and production for entities operating in a number of EU jurisdictions.	

[46] As per the US Federal Government program – the New Source Performance Standard OOOO (see Task 1)

4.2.5 Overview of key types of options within an EU framework

An overview analysis of the characteristics of key types of options which could be considered by the Commission is set out below:

REGULATION

Key characteristics:

- Direct form of law, the National government of the MS does not have to take action to implement it.
- It will come into immediate effect within each MS.
- Inflexible; it must be applied in its entirety and an MS cannot select only those provisions of which it approves.
- Most commonly used EU legislative instrument.

Approach to development of legislation:

- Likely to be the Ordinary Legislative Procedure (formerly Co-decision). See further details of process below.

Implementation of legislation:

- Directly applicable in every MS.

Harmonization across EU:

- Fully harmonized - the same law will apply regardless of international borders.

Timing:

- The Ordinary Legislative Procedure usually takes 12-18 months (see further below).

DIRECTIVE

Key characteristics:

- Binding as to objective only. Allows intervention in MS, economic and legal structures to be more subtle. MS can take account of special domestic circumstances when implementing.
- However, in certain circumstances Directives can be drafted in a very prescriptive and detailed manner thus leaving the MS with little flexibility during implementation.
- Can apply to one, some or all MS.

Approach to development of legislation:

- Likely to be the Ordinary Legislative Procedure (formerly Co-decision). See further details of process below.

Implementation of legislation:

- Not directly applicable. Requires the MS to take action e.g. to adopt / introduce implementing legislation in each MS.

Harmonization across EU:

- It may only apply to one or some MS and therefore does not ensure complete harmonization across the EU.
- Because a Directive is binding in terms of objective only, inconsistencies may appear in the standard/type of the implementing legislation introduced across the EU.

Timing:

- The Ordinary Legislative Procedure can take as little as 12-18 months but can often take significantly longer and is often preceded by several years of preparation, such as the publication of reports and consultations (see further below).
- MS will be given a deadline by which to adapt their national laws in line with the Directive. This allows for differing national situations and can lead to infraction proceedings.

DECISION

Key characteristics:

- Relates to specific cases / individuals / bodies.
- It is only binding on those to whom it is addressed.
- Binding in its entirety and therefore inflexible.

Approach to development of legislation:

- Likely to be the Ordinary Legislative Procedure (formerly Co-decision). See further details of process below.

Implementation of legislation:

- Directly applicable to those to whom it is addressed.

Ability to update:

- Addressees will be listed in the decision and the list cannot thereafter be extended / amended. A new decision would be required if further addressees were identified.

Harmonization across EU:

- It is of individual application to each addressee.

Timing:

- The Ordinary Legislative Procedure usually takes 12-18 months (see further below).

RECOMMENDATION

Key characteristics:

- Allows EU institutions to express a view/statement on a particular issue.
- Calls upon the addressee to act in a particular way.

- Not binding and does not impose any legal obligations on addressees. It is therefore only of persuasive value, but can be a pre-cursor to legally binding legislation

Approach to development of legislation:

- The EU institution will issue the recommendation, providing background information / evidence as evidence of the reasoning behind this.
- The addressee will be invited to take the necessary measures to promote the recommendation by a certain date and to report any measure taken to the issuing institution for monitoring purposes.

Implementation of legislation:

- The simplified procedure is used for adoption of non-binding instruments, especially recommendations and opinions issued by the Commission or the Council. The Commission can formulate recommendations and deliver opinions where it considers it necessary.

Harmonization across EU:

- May be addressed to all MS or to individual bodies.

Ability to amend:

- N/A

Timing:

- Uncertain

OPINION

Key characteristics:

- It gives an assessment of a given situation or development in a MS or the EU as a whole.
- It prepares the way for subsequent, legally binding acts.
- It is of a persuasive nature but is not binding and does not impose any legal obligations.

Approach to development of legislation:

- As above in respect of Recommendations

Implementation of legislation:

- N/A

Harmonization across EU:

- N/A

Ability to amend:

- N/A

Timing:

- An opinion may be issued whilst other legislative instruments are being implemented.

AMENDMENTS TO LEGISLATION (OVERVIEW)

Where existing legislation is to be amended, it is preferable for a legislative instrument to be amended by the same type of legislative instrument (i.e. a Directive should be amended by a Directive). In particular, it is recommended that a Regulation is not amended by a Directive. However, certain provisions of legislation leave the choice of the type of amending act to the institutions, by granting them power to adopt 'measures' or by expressly mentioning several possible types of act. In addition, the instrument being amended may have provided for amendment to be made by another type of instrument.

EU legislation can provide that non-essential elements of legislation can be adopted pursuant to the scrutiny process, which allows for a flexible approach to be taken to updating legislation. For example, this approach has been used under the EU ETS Directive for adopting and amending the Registries Regulation and under the Renewable Energy Directive for adopting sustainability criteria. This approach could potentially be used for implementing shale gas standards set out in legislation.

Under this process, the Commission submits a draft of the proposed measures to be opined on by the scrutiny Committee. The process of scrutiny can take a little over three months in a best case scenario. However, were there any disagreements, the timeline would be extended.

ORDINARY LEGISLATIVE PROCEDURE

In summary, the Ordinary Legislative Procedure is as follows:

1) Legislative proposal is submitted by the Commission to the EP.
2) First reading of the proposal in the EP and then the EC. If the EP and EC are in agreement as to the form of the proposal then the proposal is adopted and the legislative process ends.
3) If the EC does not agree with the EP's position, it informs the EP of the reasons why and the proposal goes back for a second reading in the EP and the EC.
4) The EC would then either (i) approve the EP's amendments, in which case the legislation is adopted or (ii) not approve all the EP's amendments, in which case the conciliation procedure would begin.
5) The Conciliation Committee will attempt to reach agreement on a joint legislative text by a qualified majority. If there is no agreement, the process ends.
6) If the Conciliation Committee does approve a joint text, the EP and the EC can adopt the act in accordance with the joint text. The EP may still reject the proposed legislation by a majority of the votes cast.

The Ordinary Legislative Procedure usually takes 12 to 18 months. However, this can be extended significantly.

Issues which could result in timing extensions include:

- Whether or not the subject matter of the legislation is particularly sensitive / divisive;
- Significant disagreements between EU institutions e.g. EP and Commission as to legislation;
- The extent to which different Member States / political groupings' interests are aligned;
- The extent of external interest from e.g. NGOs / business.

4.3 Evaluation of longlist of policy options

Table 9 presents the evaluation of the policy options against the criteria. Table 11 shows the range of criteria that were used to assess the identified policy options systematically.

Table 9 Evaluation of policy options against criteria

Policy Option		Legal criteria			Economic criteria		Environmental criteria			Feasibility criteria		Stakeholder acceptance	Flexibility	Access to infrastructure	Transparency
No	**Description**	Compatibility of possible responses with overriding EU principles such as subsidiarity and proportionality	Compatibility with existing legislative instruments	Compatibility with practical, commercial considerations and legal certainty / enforceability	Cost-effectiveness of potential emission reduction techniques necessary to comply with the policy options	Administrative burdens on businesses	Degree of certainty in achieving desired level of fugitive GHG emission reductions	Co-benefits through reductions in other pollutant releases	Potential negative environmental impacts	Potential timescales for operability	Practical hurdles to be surmounted prior to full implementation	Politically acceptability	Allowing incorporation of technical developments of abatement technologies and practices	Ensuring that lack of easily accessible infrastructure cannot be used as an excuse for non-action on fugitive emissions	Reliable monitoring of fugitive emissions and ensuring open access to the data
1	**No EU-level intervention**	Response is in line with both subsidiarity and proportionality. However the regulation of shale gas may not be appropriately addressed at MS level and therefore MS level action may not be effective. Hence to accord with the principle of subsidiarity this may favour an EU-level intervention.	This approach would not affect existing legislative instruments. However this approach may lead to ambiguous interpretation of existing legislation and inconsistent standards and approaches across the EU.	May lead to inconsistent approach across EU. Some MS may issue legislation, others may implement guidance, and some may choose not to address the issue at all. No enforcement power at EU level other than the threat of potential future legislation or under existing legislation which does not specifically address shale gas. If MS guidance / legislation is implemented, it might be wrongly applied / interpreted at MS level and there would be little the EU could do to prevent this. Lack of harmonized regulatory approaches at EU level can create distortions of competitiveness and competition. Further, the EU may disagree with the approach adopted in different MS and there would be little the EU could do to prevent this. Several MS have signalled that they are waiting for EU-level activity on this, as they do not have the expertise on shale gas themselves.	Not cost effective given that each MS may adopt different technology and equipment requirements; resulting in a wide range of costs to abate the emissions. Some MS may not adopt any regulations.	Will vary depending on the level of regulation at the MS level. Lack of harmonized regulatory approaches at EU level can create distortions of competitiveness and competition.	Highly uncertain given that the regulation (or lack of) will vary across the MS.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	Potentially N2O emissions from flaring.	Uncertain and depending on the regulatory initiatives in the MS.	Uncertain and depending on the regulatory initiatives in the MS.	Civil society is unlikely to have confidence in this approach as there is a high risk of under-regulation. Industry is likely to appreciate the flexibility of the approach but may have concerns about the inconsistency of approaches between MS.	This option provides significant regulatory flexibility to the MS and the ability to adapt to local circumstances and conditions. It also enables industry and environmental organisations to develop their own guidelines and to integrate the latest technical developments. However, if MS decide to develop their own regulations, the level of flexibility will depend on the specific rules within each MS.	Uncertain and depending on the regulatory initiatives in the MS.	This option does not guarantee any level of transparency. It will depends on the legislations developed by the MS or on the good will of the industry.
2	**EU level information exchange**	See 1 above.	See 1 above.	As for policy option 1 above. Information sharing will not necessarily lead to the concrete outcomes that can be achieved by legislation and enforcement. There may be potential data protection and commercial confidentiality issues and therefore participants may not freely exchange information.	Potentially cost effective for companies that volunteer to participate, if the information exchange is focused around the implementation of cost effective technologies. Companies that choose to not volunteer to participate and do not implement abatement technologies will not incur costs. Potential for non-cost effective emissions to go unabated as industry may not volunteer such standards and technologies.	Operators today, maintain records and data logs from their production operations. No proprietary data and information that is already collected will be shared with other companies. The cost of sharing information and best practices would be small.	Highly uncertain since it is dependent on the willingness of companies to share and participate in the program.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	Potentially N2O emissions from flaring.	6 to 18 months	Convince the different stakeholders to participate in the information sharing efforts and to share their data.	As for policy option 1 above, though all interested entities are likely to appreciate there being a forum for discussion of these issues. Industry is likely to appreciate the flexibility of the approach but may have concerns about the inconsistency of approaches between MS if they decide to develop their own legislation.	High level of flexibility	Uncertain	This option does not guarantee any level of transparency.
3	**EU level guidance on best**	See 1 above.	See 1 above.	As for policy option 1 above, though with a reduced likelihood of inconsistency of	Potentially cost effective for companies that volunteer to adopt best practices given	Administrative burden will be modest given that	Highly uncertain given the	- Methane recovery. - VOC and HAPPS	Potentially N2O emissions	1 to 24 months	Convince the different stakeholders to	As for policy option 1 above, though many interested entities are	High level of flexibility, this policy option	Uncertain	This option does not guarantee any level of

Policy Option		Legal criteria			Economic criteria		Environmental criteria			Feasibility criteria		Stakeholder acceptance	Flexibility	Access to infrastructure	Transparency
No	Description	Compatibility of possible responses with overriding EU principles such as subsidiarity and proportionality	Compatibility with existing legislative instruments	Compatibility with practical, commercial considerations and legal certainty / enforceability	Cost-effectiveness of potential emission reduction techniques necessary to comply with the policy options	Administrative burdens on businesses	Degree of certainty in achieving desired level of fugitive GHG emission reductions	Co-benefits through reductions in other pollutant releases	Potential negative environmental impacts	Potential timescales for operability	Practical hurdles to be surmounted prior to full implementation	Politically acceptability	Allowing incorporation of technical developments of abatement technologies and practices	Ensuring that lack of easily accessible infrastructure cannot be used as an excuse for non-action on fugitive emissions	Reliable monitoring of fugitive emissions and ensuring open access to the data
	practices (options 2 and 3 are not mutually exclusive)			approach by different MS. Best practice guidance would not have the same legislative standing as, for example, formal BREFs (see further below).	that the adoption of any EU level guidance on best practices will be influenced by the input from industry representatives. Companies that choose to not adopt best practices will not incur costs. Potential for non-cost effective emissions to go unabated as industry may not volunteer such standards and technologies.	there are no reporting or monitoring requirements.	best practices are not formally binding. Best practice guidance would not have the same legislative standing as formal BREFs (see option 8b).	reductions. - NGL recovery.	from flaring.		participate in the information sharing efforts and to share their data. A process would need to be implemented for development/ adoption of the Guidance. This could be time-consuming (and may potentially be even more complex than following the formal EU legislation process, depending on how the process was managed and stakeholder buy-in).	likely to appreciate the development of harmonised guidance. Civil society may be wary of approaches that are less inclusive of their views than the formal legislative process.	could also creates incentives for innovation depending on how equipment suppliers respond.		transparency.
4	**Promote an EU level, industry-led voluntary approach to minimizing on-site fugitive GHG emissions**	See 1 above	See 1 above.	It may be difficult for the Commission to encourage this approach without resorting to the threat of implementing legislation if such approach does not materialise / is not robust enough. Industry may not set best practice, and are unlikely to require / encourage uptake of measures that will significantly increase production costs. Industry may be unwilling / unable to share information with competitors. Industry may be diverse with participants seeking differing and potentially contradictory outcomes. It may be difficult for the EU to be involved in the process of development of any approach.	Potential for highly cost effective emission reductions since the effort will be industry-led. Potential for non-cost effective emissions to go unabated as industry may not volunteer such standards and technologies.	Low administrative burdens since industry will attempt to minimize that.	Highly uncertain. However experience in North America has shown industry-led voluntary approaches to be effective in achieving significant emission reductions.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	Potentially N2O emissions from flaring.	6 to 18 months	Ensure stakeholders buy-in into the scheme.	Civil society is likely to be concerned that an industry-led approach may not be sufficiently robust or lead to best practice being adopted. Industry is likely to appreciate the flexibility of the approach but may have concerns about the inconsistency of approaches between MS if they decide to develop their own legislation.	This is likely to be the most flexible approach and, depending on industry buy-in, could be developed rapidly.	Uncertain	This option does not guarantee any level of transparency.
5	**Create a "name and shame" or "star rating"**	See 1 above	See 1 above.	This option could complement rather than replace other policy responses. A measure of	Cost effectiveness will depend on the performance targets within each rating band. A high star rating that	Administrative burden of disclosing reported GHG reduction	Highly uncertain since not all companies	- Methane recovery. - VOC and HAPPS reductions.	Potentially N2O emissions from flaring.		- Agree on the design of the "name and shame" or "star	Civil society is likely to think that mechanisms such as these are not	Depending on the design of the mechanism, this option has a	Uncertain	This option could ensure a certain level of transparency if

Policy Option		Legal criteria			Economic criteria		Environmental criteria			Feasibility criteria		Stakeholder acceptance	Flexibility	Access to infrastructure	Transparency
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	system of "compliance"			this type is likely to be more subjective and less effective than a mandatory compliance regime. Such initiatives have been used elsewhere (e.g. UK's Carbon Reduction Commitment (though note that Carbon Reduction Commitment league tables have now been abandoned))	will require higher emission reductions will not be as cost effective on a per ton basis as a lower star rated performance level.	activities will be modest since the reported activities are not subject to verification or enforcement.	will be motivated to implement abatement technologies.	- NGL recovery.			rating system" mechanism (who will be included in the design process? How will the rating mechanism work? Etc.) - Assessment of the relevant entities' compliance with the scheme	adequately robust. Industry is likely to appreciate the flexibility of the approach but may have concerns about the inconsistency of approaches between MS if they decide to develop their own legislation. Industry may also be reluctant to the use of a "name and shame" mechanism.	relatively high level of flexibility.		compliance information about specific entities are made public.
6	**Establish a GHG emissions reporting framework in relation to minimizing on-site fugitive GHG emissions from shale gas exploration and production**	See 1 above.	There are already other regimes which address GHG reporting. For example, installations that are regulated under the EU Emissions Trading Scheme are required to monitor, report and have their emissions verified. Further, as Parties to the UNFCCC and its Kyoto Protocol, the European Union and Member States are required to report annually on their GHG emissions. We do not envisage that a reporting framework would be incompatible with EU legislation.	Monitoring would not necessarily lead to increased uptake of best practice in respect of fugitive GHG minimisation but would provide a body of information if verifiable. Given the short duration of the well completion emissions, by the time reported emissions are verified and published it may be too late to take any significant action on those emissions. <u>Mandatory reporting:</u> If legislation was required this could be more burdensome to implement than a voluntary system and there may be difficulties in verification of data and enforcement. <u>Voluntary reporting:</u> Entities may be unwilling to disclose all information because of commercial sensitivity / because it would be expensive or burdensome to compile the information and therefore undermine the reporting process. There may also be data variances and difficulties in verification (if there is verification)	Not applicable since this is a reporting framework.	This will be highly dependent on the number of emission sources covered and the monitoring requirements. The larger the number of emission sources covered and the more stringent the reporting requirements, the more burdensome the legislation.	None. Because this would be a reporting rule. There would be no requirement for fugitive GHG minimisation.	None	None		- The EC will have to define which calculation methodologies operators must use - Verification of the submitted data either by authorities or by third parties	If implemented without other policies, industry is likely to see reporting as a less burdensome policy response than other policy responses. However, if a mandatory reporting scheme is developed, it could represent a certain level of administrative burden for the industry and the MS if they are in charge of the verification procedure. Civil society will be concerned that reporting on its own does not lead to best practice in respect of fugitive GHG minimisation. This option does not imply any requirement for GHG minimisation. Civil society might also argue that given the short duration of the well completion emissions, by the time reported emissions are verified an published it may be too late to take any significant action on these emissions.	This option does not ensure the uptake of new technical developments as it only tackles reporting.	No	Depending on whether reporting would be mandatory or voluntary and whether the scheme would include public dissemination of data, this option has the potential to ensure a high level of transparency.

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												Emissions data collected can be made publically available. For instance, in January 2012, the US EPA made the first year of GHGRP reporting data available to the public through its interactive Data Publication Tool, called Facility Level Information on Greenhouse gases Tool (FLIGHT).			
7	**Encourage / recommend MSs to go beyond existing EU legislation**	See 1 above. An approach which encourages MS to intervene without introducing formal legislation may be seen as more consistent with the principle of subsidiarity than the introduction of EU legislation. However, as such approach is arguably not likely to be as effective as a formal EU legislative approach, this could mitigate against the acceptability of this approach from the point of view of subsidiarity.	See 1 above.	It may be difficult to get MS to implement tighter legislation in a particular way or a timely fashion without EU legislation. This approach is likely to leave regulatory "gaps" that would need to be closed by other policy responses, for example with respect to reporting requirements.	Each MS may adopt different technology and equipment requirements; resulting in a wide range of costs to abate the emissions. Some MS may not adopt any regulations.	Administrative burden will be dependent on the type of guidance provided by the EU.	Highly uncertain in achieving desired level of GHG emission reductions given that only guidance will be given to MS level, with no EU level enforcement.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	Potentially N2O emissions from flaring.		- Uncertain and depending on the regulatory initiatives in the MS - If this option is accompanied by the development of guidance for MS, this will have to be taken into account	This approach may not be perceived as particularly robust by the civil society. They might also be concerned by the low level of uptake by MS with a high interest in shale gas exploitation. Industry is likely to have concerns about the inconsistency of approaches in the MS.	This option does not ensure the uptake of new technical developments. It will depends on the regulatory initiatives taken by the MS.		This option does not guarantee any level of transparency. It will depends on the legislations developed by the MS.
8	**Adapt individual pieces of existing EU legislation**	See 1 above. As environmental protection is an objective of the Treaties, and regulation of fugitive GHG emissions concerns environmental protection, it would be difficult to argue that EU-level action is disproportionate, provided that such	This approach would vary / amend existing legislation. This would have to be done in a manner that is both internally and externally consistent.	Adapting individual pieces of existing legislation in the absence of a holistic piece of shale gas legislation can be legislatively burdensome. It should also be noted that other pieces of legislation may already be undergoing amendment / may have just done so and legislators may be unwilling to support further amendment. It could also in certain circumstances give rise to conflict of laws.											

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		regulation will demonstrably protect the environment.													
8a	**Specific inclusion of shale gas production installations in Annex I of the EU ETS Directive**	Provided it can be demonstrated that this response would be more effective in minimising GHG emissions from shale gas than items 1 - 7 this option is likely to be more consistent with the principle of subsidiarity than items 1-7 (on the basis that items 1-7 are less likely to be effective). As a result of the practical difficulties with this legislative approach (see table [**cross refer to table setting out legislative analysis**] above), other legislative options may be more proportionate.	This would require amendments to existing legislation.	If technically possible to implement this would be a market-driven approach subject to external verification and legally binding compliance. However we have identified a number of challenges to the effectiveness of this legislative approach compared to other legislative options (see table7 in the interim report). Therefore other legislative responses may be more appropriate.	The cost effectiveness of the potential emission reduction techniques will depend on the prevailing EU ETS carbon price. Given that shale gas completions are short term events and may not be currently included in facility emission baselines, the cost effectiveness under this option is uncertain.	The administrative burden will increase marginally given that natural gas producers are already familiar with the EU ETS system and it's requirements.	Uncertain given that the effectiveness of the EU ETS would depend on the prevailing EU ETS price for carbon. At the current carbon price, the EU ETS would be limited in achieving the desired level of fugitive GHG emission reductions.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	Potentially N2O emissions from flaring.	A modification of the EU ETS Directive would be required (co-decision process). This could take between one and two years (though any amendment may be able to be included in any current EU ETS legislative review). The MRV Regulation is also likely to need to be updated (comitology).	- One significant practical issue to be assessed is the ability to monitor, report and verify fugitive shale gas emissions	Some jurisdictions where shale gas production is subject to a moratorium may be of the view that further legislation is not necessary. Some entities are likely to be of the view that GHG emissions in the energy sector are already regulated under the existing EU ETS and that no further regulation is necessary. If legislation is necessary, some entities are likely to prefer a more flexible market-based approach to GHG regulation (such as under the EU ETS) to a command and control approach (such as under the IED). The regulatory compliance burdens that may result from EU ETS monitoring, reporting and verification may be seen as overly onerous. A market-based approach may be viewed by civil society as less attractive than a traditional command and control approach. This is likely to be particularly the case given the current low EU ETS carbon price. It may also be thought that relying on the EU ETS is less likely to lead to	As this option is market-based and the choice of the technologies used to abate GHG emissions is left to the industry. On its own this option is unlikely to lead to best practice being adopted.	No	Under this option monitoring, reporting and verification of GHG emissions would be required. A high level of transparency is therefore expected.

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												use of technology with the lowest GHG impact, where the cost of purchasing such equipment is greater than the cost of EU ETS compliance.			
8b	**Specific inclusion of shale gas activities in Annex 1 of the IED**	Provided it can be demonstrated that this response would be more effective in minimising GHG emissions from shale gas than items 1 - 7 this option is likely to be more consistent with the principle of subsidiarity than items 1-7 (on the basis that items 1-7 are less likely to be effective).	This would require amendments to existing legislation.	Environmental impacts would be regulated under a permit. Detailed information (e.g. releases to the environment / environmental impact) available to the public. Public consultation part of the permitting requirements under the IED. Enforcement / sanctions would be determined by existing MS enforcement / sanctions for IED. Development of a shale gas sector specific BREF for detailed guidance and emission limits. BAT-AELs would be determined based on a detailed assessment of EU operators and worldwide suppliers but could be distinguished by site-specific factors allowing for different environmental concerns in different sites. The BREF document would be updated/renewed at a pre-determined frequency (e.g. every 6 years).	Potentially cost effective for companies as the same EU BAT will be enforced across all MS.	Might be onerous if shale gas size specific permitting requirements are enforced.	High certainty given that the emission limit values would be set based on BAT conclusions and verified using BAMM. Furthermore; enforcement/ sanctions that are determined by existing MS enforcement/ sanctions for IED would force producers to comply.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	Potentially N2O emissions from flaring.	This could take between one and two years	Preparation of a 'BREF' document setting out the best available techniques (BAT) for mitigation of climate impacts of shale gas extraction, giving information on, for example, techniques and processes used, current emission levels, etc, as well as 'BAT conclusions' which would form the basis of permits under the (IED), and which cannot be deviated from except in specific and well justified / documented cases.	Appropriate and robust regulation of shale gas operations may be welcomed and, depending on the MS permitting regime, there may be the ability to have input into the permitting process. The different stakeholders (EU Member States, industry, civil society) will probably welcome the opportunity to participate in the development process of the BAT/BREF.	The BREF document would be updated/renewed at a pre-determined frequency (e.g. every 6 years) offering the opportunity to include new technical developments. However, this updating process is time consuming.	No	Under this option, detailed information on the shale gas facility, its releases to the environment and their environmental impact would be made available to the public.
8c	**Specific inclusion of shale gas activities in Annex 1 of the EIA Directive**	The Union does not take action (except in the areas that fall within its exclusive competence), unless it is more effective than action taken at national, regional or local level. MSs could make EIAs compulsory (at their discretion) under Annex 2 of the EIA and therefore the Commission would not need to action this proposal.	This would require amendments to existing legislation.	Environmental impacts from the shale gas activities would be identified and considered in the EIA process and techniques considered for mitigation of any identified impacts. Potential monitoring or further investigations to be specified in planning consents. Detailed information on shale gas facilities and their emissions and environmental impacts would be made available to the public. Public consultation is part of the EIA process.	Not cost effective given that there is no specific inclusion in the EIA of GHG emission mitigation techniques, each EIA may require different technology and equipment requirements; resulting in a wide range of costs to abate the emissions. Some EIAs may not require abatement.	High administrative burden if each new well is subject to an EIA.	Highly uncertain since mitigation techniques are not part of an EIA.	None	None	This could take between one and two years	Establishment of what environmental impact factors to be taken into account would need to be fully considered.	Aids understanding of the issues and mitigation measures may give comfort that the effects on the environment have not been overlooked. Ability to challenge the development on EIA issues. Civil Society will probably welcome the opportunity to influence the EIA process through the public consultations. However the fact that GHG emission impacts and mitigation may not be	This option does not ensure the uptake of the latest technological development by the industry.	No	Under this option, detailed information on shale gas facilities and their emissions (not integrating GHG emissions per se) and environmental impacts would be made available to the public.

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												included in the EIA is likely to be perceived as lack of robustness and efficiency of this policy option. The industry will probably consider the development of an EIA for each well as a very heavy, expansive and time-consuming process.			
8d	**Lowering the flow rate threshold from wells in Annex 1 of the EIA Directive**	Provided it can be demonstrated that this response would be more effective in minimising GHG emissions from shale gas than items 1 - 7 this option is likely to be more consistent with the principle of subsidiarity than items 1-7 (on the basis that items 1-7 are less likely to be effective).	This would require amendments to existing legislation.	Not all shale gas developments would be covered by the provision.	See 8(c) above.	High administrative burden if exploration wells are included. The NSPS OOOO currently excludes exploration wells and low pressure wells from some of its requirements.	See 8(c) above.	None.	None	This could take between one and two years	Establishment of the appropriate threshold and what environmental impact factors to be taken into account would need to be fully considered.	See comments at 8(c) above. Although no certainty that all projects will be subject to an EIA.	See comments at 8(c) above.	No	See comments at 8(c) above.
8e	**Specific inclusion of shale gas exploration activities in Annex 2 of the EIA Directive**	Provided it can be demonstrated that this response would be more effective in minimising GHG emissions from shale gas than items 1 - 7 this option is likely to be more consistent with the principle of subsidiarity than items 1-7 (on the basis that items 1-7 are less likely to be effective). However it depends on the action taken by MS to interpret whether or not shale gas activities require an EIA, as currently under Annex 2 it is at their discretion.	This would require amendments to existing legislation.	This approach still allows for MS discretion as to whether an EIA is required. Therefore, potential MS inconsistency of approach.	See 8(c) above.	See 8(d) above.	See 8(c) above.	None.	None	This could take between one and two years	Establishment of what environmental impact factors to be taken into account would need to be fully considered and how there could be consistency of approach taken in different Member States	See comments at 8(d) above.	See comments at 8(d) above.	No	See comments at 8(d) above.
8f	**Amendment of definition**	This is potentially in line with both	This would require	It would be difficult to amend the definition of "waste" in an	Potentially cost effective, depending on the ability to	Non-gaseous wastes from shale	Potentially less certain	This would depend on the relevant	None	This could take between	It would be challenging (and	This is likely to be less politically	Low level of flexibility as	No	The Mining Waste Directive

Policy Option		Legal criteria			Economic criteria		Environmental criteria			Feasibility criteria		Stakeholder acceptance	Flexibility	Access to infrastructure	Transparency
No	**Description**	Compatibility of possible responses with overriding EU principles such as subsidiarity and proportionality	Compatibility with existing legislative instruments	Compatibility with practical, commercial considerations and legal certainty / enforceability	Cost-effectiveness of potential emission reduction techniques necessary to comply with the policy options	Administrative burdens on businesses	Degree of certainty in achieving desired level of fugitive GHG emission reductions	Co-benefits through reductions in other pollutant releases	Potential negative environmental impacts	Potential timescales for operability	Practical hurdles to be surmounted prior to full implementation	Politically acceptability	Allowing incorporation of technical developments of abatement technologies and practices	Ensuring that lack of easily accessible infrastructure cannot be used as an excuse for non-action on fugitive emissions	Reliable monitoring of fugitive emissions and ensuring open access to the data
	of "waste" in Mining Waste Directive	subsidiarity and proportionality, depending on its effectiveness. Effectiveness would depend on the ability to effectively amend the definition of "waste". However, a more holistic approach would be achieved by regulation of fugitive GHG emissions under the Industrial Emissions Directive (see option 8b above).	amendments to existing legislation.	appropriate manner.	appropriately amend the definition of "waste", but less holistic a regulatory approach than under option 8b. The amended definition of "waste" would be applied across all Member States.	gas exploration and production facilities are likely to already be regulated under the Mining Waste Directive. Additional burden likely to be slight depending on how the modified definition of "waste" is drafted.	in terms of regulatory outcome than option 8(b) above.	amendment of the definition of "waste"		one and two years	extremely difficult) to amend the definition of "waste" in an appropriate manner	acceptable than an approach under option 8b as it requires amendments to be made to primary legislation but the outcome would be less holistic.	Directive would need to be amended to make further amendments to definition of waste		contains a number of provisions in respect of monitoring, permitting and public participation so there would be significant transparency
9	**Accelerate the take-up of abatement techniques through financial incentives (such as a subsidy)**	This is in line with both subsidiarity and proportionality. However, it may not achieve adequate impacts in the sector in each MS, and therefore this approach may be less consistent with the principle of subsidiarity than other options.	This may require new legislative instruments at EU level (if such incentives were to be implemented at EU level). Alternatively such incentives could be implemented at national level.	Direct grants are unlikely to be desirable unless the relevant technologies are particularly innovative. Any certificate-based / feed-in tariff type model is likely to be difficult to implement. Operators may benefit from surplus profit if capital costs are covered by funding and if no consideration is given to revenue from extra sales of gas. There may be difficulties in establishing a level playing field for funding awards which may lead to disproportionate application in different Member States.	Grants are small scale and provide no clear cost effective path for implementation across the EU, over possibly thousands of well sites. Certificates such as with biofuels are a means to ensure compliance, and not generally attributable to the deployment of cost effective emissions abatement.	Burden might be high if stringent reporting and monitoring requirements are put in place.	Uncertain.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	N2O emissions from flaring.	This would depend on the choice of the financial incentive	This would depend on the choice of the financial incentive	Civil society is likely to be unsupportive if measures impose additional costs on the public with no certainty that significant improvements would be made by the industry.	High level of flexibility	No	This option does not guarantee any level of transparency.
10	**Develop specific EU framework for unconventional fossil fuels**	This approach is theoretically in line with both subsidiarity and proportionality. However, we note this will not depend on the EU legislation developed or the specific legislative instrument but will be dependant on the specific content of the legislation. See our comments above on the consistency of particular	This may affect existing legislative instruments which may need to be varied / amended depending on the scope and content of the specific piece of legislation.	This allows a holistic and harmonised approach and could encompass voluntary approaches. Some commercial entities may desire common pan-European regulation to make it easier for them to operate across borders. Without consistent EU-wide legislation, compliance with different legislation in a number of MS may increase the administrative and operational burdens of shale gas exploration and production for entities operating in a number of EU jurisdictions.	Highly cost effective since the emission reduction techniques will be tailored specifically to EU shale gas operations.	Burden might be high if stringent reporting and monitoring requirements are put in place.	High degree of certainty since the rule would specifically target shale gas emissions.	- Methane recovery. - VOC and HAPPS reductions. - NGL recovery.	N2O emissions from flaring.	Elaboration of a "Shale Gas Directive" is likely to require the co-decision process. This could take 1 to two years.	This would depend on the content of the legislation but would likely to be the most burdensome approach as it will involve the formal legislative process, including amendments to existing legislation, which may be resisted. Ordinary Legislative	A holistic approach to shale gas regulation is likely to be seen as attractive. Whether the legislation is politically acceptable is likely to depend on its content. This option is likely to be the most acceptable to civil society and allow a comprehensive regulation of the sector, addressing all the environmental impacts likely to be of most concern to local populations (probably	Once set up the level of flexibility of this policy option will depend on the structure and details of the legislation.	Under this option it could be possible to introduce provisions for equal access to infrastructure.	Under this option monitoring, reporting and verification of GHG emissions could be required.

Policy Option		Legal criteria			Economic criteria		Environmental criteria			Feasibility criteria		Stakeholder acceptance	Flexibility	Access to infrastructure	Transparency
No	Description	Compatibility of possible responses with overriding EU principles such as subsidiarity and proportionality	Compatibility with existing legislative instruments	Compatibility with practical, commercial considerations and legal certainty / enforceability	Cost-effectiveness of potential emission reduction techniques necessary to comply with the policy options	Administrative burdens on businesses	Degree of certainty in achieving desired level of fugitive GHG emission reductions	Co-benefits through reductions in other pollutant releases	Potential negative environmental impacts	Potential timescales for operability	Practical hurdles to be surmounted prior to full implementation	Politically acceptability	Allowing incorporation of technical developments of abatement technologies and practices	Ensuring that lack of easily accessible infrastructure cannot be used as an excuse for non-action on fugitive emissions	Reliable monitoring of fugitive emissions and ensuring open access to the data
		proposals with subsidiarity and proportionality. As a general matter, it is more likely that instruments that can be applied flexibly, such as a Directive, will be more consistent with subsidiarity than a Regulation, which is directly applicable in MS law. However, as also noted in section 4.2.5 of the report, where a Directive is very specifically drafted in practice the MS may be left with little discretion as to its application.									Procedure is as follows: 1) Legislative proposal is submitted by the Commission to the EP. 2) First reading of the proposal in the EP and then the EC. If the EP and EC are in agreement as to the form of the proposal then the proposal is adopted and the legislative process ends. 3) If the EC does not agree with the EP's position, it informs the EP of the reasons why and the proposal goes back for a second reading in the EP and the EC. 4) The EC would then either (i) approve the EP's amendments, in which case the legislation is adopted or (ii) not approve all the EP's amendments, in which case the conciliation procedure would begin. 5) The Conciliation Committee will attempt to reach agreement on a joint legislative text by a qualified majority. If there is no agreement, the process ends. 6) If the Conciliation Committee does	non-climate related).			

Policy Option		Legal criteria			Economic criteria		Environmental criteria			Feasibility criteria		Stakeholder acceptance	Flexibility	Access to infrastructure	Transparency
No	**Description**	Compatibility of possible responses with overriding EU principles such as subsidiarity and proportionality	Compatibility with existing legislative instruments	Compatibility with practical, commercial considerations and legal certainty / enforceability	Cost-effectiveness of potential emission reduction techniques necessary to comply with the policy options	Administrative burdens on businesses	Degree of certainty in achieving desired level of fugitive GHG emission reductions	Co-benefits through reductions in other pollutant releases	Potential negative environmental impacts	Potential timescales for operability	Practical hurdles to be surmounted prior to full implementation	Politically acceptability	Allowing incorporation of technical developments of abatement technologies and practices	Ensuring that lack of easily accessible infrastructure cannot be used as an excuse for non-action on fugitive emissions	Reliable monitoring of fugitive emissions and ensuring open access to the data
											approve a joint text, the EP and the EC can adopt the act in accordance with the joint text. The EP may still reject the proposed legislation by a majority of the votes cast.				

4.4 Selection of preferred policy options

Based on the assessment of the long list of policy options against the criteria, a shortlist has been selected:

Option 4: Promote EU-level industry led voluntary approach to minimising on-site fugitive GHG emissions

Under this option, industry would be encouraged to develop their own approach to minimising on-site fugitive GHG emissions. This could be in the form of: information exchange/ guidance/ development of an industry standard. This approach has already proven to be effective in North America with the Natural Gas Star Program (as described under Task 1). This program is supported and funded by the federal government agency the US EPA. Furthermore, the Centre for Sustainable Shale Development (CSSD) is an independent organisation launched in March 2013 which supports sustainable shale exploration and production through performance standards and third-party certification standards. CSSD has developed 15 initial performance standards for operators that are protective of air quality, water resources and climate. The performance standards were developed by reviewing existing state and federal regulations. The 15 performance standards are either as stringent as or more stringent than the existing state and federal regulations. Companies that want to be certified need to undergo a third party audit.

In the UK, in January 2013 the UK Onshore Operators Group has produced Guidelines for UK Well Operators on Onshore Shale Gas Wells (which contains a section on Minimising Fugitive Emissions).

However, there may be concern from civil society that an industry-led approach/industry standard may not be sufficiently robust or lead to best practice being adopted. In order to mitigate these concerns, this approach could be accompanied by the announcement of EU intervention in case the voluntary approach is not robust enough to lead to emissions reductions. This option could take less time to implement that either of the legislative options above.

The public consultation run by the European Commission found this option to be preferable to amending individual pieces of legislation, but significantly less preferable than the option 'Do nothing, the current framework is appropriate'. See Appendix D.

Option 8b: Specific inclusion of shale gas activities in the Annex 1 of the Industrial Emissions Directive (IED)

The Industrial Emissions Directive 2010/75/EU requires permitting 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 currently 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.

Under this option, the activities listed in Annex 1 of the IED would be revised to include shale gas activities. This would then mean that shale gas installations would be covered by Chapter 2. A further sub-option would be to include a separate new chapter for shale gas facilities to bring more specific requirements. In conjunction with this, the preparation of a ‘BREF’ document in

respect of setting out the best available techniques (BAT) for mitigation of climate impacts of shale gas extraction, giving information on, for example, techniques and processes used, current emission levels, etc., as well as 'BAT conclusions' which would form the basis of permits under the (IED), and which cannot be deviated from except in specific and well justified / documented cases. The BREF document would be updated/renewed at a pre-determined frequency (e.g. every 6 years) offering the opportunity to include new technical developments in the sector.

Option 8c: Specific inclusion of shale gas activities in Annex 1 of the EIA Directive

Under this option, the activities listed in Annex 1 of the EIA Directive would be revised to include shale gas activities. This would mean that any proposed exploratory or commercial development is subject to mandatory EIA. Nonetheless, it is noted that this option would not guarantee emission reductions as mitigation techniques are not part of an EIA. Instead, in the event of a full EIA, developers are obliged to provide required information, including a description of measures to avoid, reduce and, if possible, offset any significant adverse effects. But there is no clear obligation to do so. Implementation of measures is not explicitly required. This depends on the national implementation of the EIA Directive. There is also no clear definition of "significant" adverse effects.

Option 10: Elaboration of a specific EU framework for shale gas

This could take the form of a Regulation, Directive, Recommendation or Opinion. The scope of this framework would not necessarily be limited to fugitive emissions-specific provisions; it may also include other provisions relating to permitting, waste water usage, seismicity or health and safety. Such a framework would have the advantage of harmonising, for example, the definition of shale gas and approach to shale gas permitting throughout the EU and the identification of approved technologies / techniques and appropriate risk assessments. This would allow a holistic approach to comprehensively address all key impacts in one legislative package and at the same time ensure a harmonised approach across all Member States. It could also provide for any amendments to other relevant legislation that are required to be made (e.g. IED or EIA Directive as well as other relevant environmental legislation with regards in particular to waste, water) and for monitoring requirements.

Nonetheless this is likely to be the most burdensome approach as it will involve the formal, legislative process including amendments to existing legislation. It is estimated that the Ordinary Legislative Procedure usually takes 12 to 18 months. However, this can be extended significantly. For example, certain Member States may have objections to the implementation of a new EU framework.

This option is considered to be likely to be the most acceptable to civil society. The (draft) results from the DG ENV public consultation illustrate that just over 50% of individual respondents are in favour of this option. The results are presented in Appendix D.

5. Task 4 - Analysis of climate, environmental, social and economic impacts of most relevant policy options and provide support to impact assessment

The policy options identified in Task 3 are likely to result in various climate, environmental, social and economic impacts. This chapter analyses these impacts in order to compare the options respectively. The impacts are compared to a 'business as usual' (BAU) scenario which assumes no additional regulations for minimising on-site fugitive GHG emissions and promoting the most advanced technologies and practices of shale gas exploration and production beyond those already in place or planned at an EU or Member State level.

5.1 Overall Approach

5.1.1 Introduction

In this task, a number of steps are taken to estimate impacts of the different policy options:

1. Energy modelling
    - Develop estimates of the accessible shale gas resource base in each Member State for both the baseline (i.e., best resource base estimates) and 'high' resource base scenarios;
    - Develop supply curves to model the costs for shale gas extraction in the EU: including assumptions on uptake rates of abatement technologies;
    - Run through Enerdata's POLES model in order to model EU shale gas production and gas prices under BAU and different policy scenarios for years 2020 and 2030;
    - Based on the supply curves and outputs from POLES, estimate impacts of policy scenarios (and sensitivities) on EU energy consumption, sources of energy, energy prices and investment by the energy sector
2. Economic modeling
    - Using the E3ME model estimate economic impacts and impacts on competitiveness in specific sectors.
3. Emissions impacts
    - Estimate impacts on GHG emissions and air pollutants.

The energy and economic modeling was undertaken jointly for this report and for a related report for DG ENV "Macroeconomic Impacts of Shale Gas Extraction in the EU". Where the approaches are common to both reports, the descriptions of the work undertaken are given in the DG ENV report.

5.1.2 Policy modelling scenarios

In line with the EC's requirements for the impact assessment scenarios and energy modelling to be consistent across this study and the abovementioned DG ENV study, the following scenarios have been modelled:

- **Base Case** ("current") conditions, with best estimates applied for the EU-27 shale gas resource base and world economic growth (see Appendix E).

1. Adoption of new, **more stringent shale gas risk management policies** e.g. elaboration of specific EU framework for shale gas (which could take the form of a Regulation, Directive, Recommendation, Opinion, etc.), which is policy option 10 from Task 3, or an amendment to the Industrial Emissions Directive (IED), which is policy option 8b from Task 3 — with the same estimates applied for the EU shale gas resource base, world economic growth, and EU climate policies as in the base case.
2. Adoption of **less stringent shale gas risk management policies (relative to scenario 1),** e.g. promotion of an EU-level voluntary approach to minimise environmental risks (including industry standards, guidance, information exchange etc), which is policy option 4 from Task 3, or an amendment to the EIA Directive, which is policy option 8c from Task 3 - with the same estimates applied for the EU shale gas resource base, world economic growth, and EU climate policies as in the base case.

This is illustrated in Table 10.

The levels of uptake of GHG mitigation measures assumed in the base case and alternative policy scenarios, as well as their assumed costs, are shown in Table 12, with further details given in Appendix F. The equivalent details for wider environmental risk management measures are based on the AMEC report for DG ENV "Technical support for assessing the need for a risk management framework for unconventional gas extraction". The details of these measures were fed into the supply cost curves as part of the overall energy modeling undertaken for this study.

Table 10 Scenarios for POLES modelling

Case No	Shale gas risk management policy option		Value used for key sensitive parameter		
	1[a]	2[b]	Shale gas resource base	World economic growth	EU climate policies
Base case			Best estimate	Best estimate	In line with 2050 roadmap GHG reduction
1	X		Best estimate	Best estimate	Same as in base case
2		X	Best estimate	Best estimate	Same as in base case

[a] More ambitious shale gas risk management policy option relative to risk management policy option 2; modelled in POLES via an impact on production costs.

[b] Less ambitious shale gas risk management policy option relative to risk management policy option 1; modelled in POLES via an impact on production costs.

Table 11 Criteria for assessment of policy options

Criteria for assessment	Type
Legal criteria	Compatibility of possible responses with overriding EU principles such as subsidiarity and proportionality
	Compatibility with existing legislative instruments
	Compatibility with practical, commercial considerations and legal certainty / enforceability
Economic criteria	Cost-effectiveness of potential emission reduction techniques necessary to comply with the policy options
	Administrative burdens on businesses
Environmental criteria	Degree of certainty in achieving desired level of fugitive GHG emission reductions
	Potential negative environmental impacts
	Co-benefits through reductions in other pollutant releases
Feasibility criteria	Potential timescales for operability
	Practical hurdles to be surmounted prior to full implementation
Stakeholder acceptance	Politically acceptability
Flexibility	Allowing incorporation of technical developments of abatement technologies and practices
Access to infrastructure	Ensuring that lack of easily accessible infrastructure cannot be used as an excuse for non-action on fugitive emissions
Transparency	Reliable monitoring of fugitive emissions and ensuring open access to the data

Note that the outputs from the energy modeling are based on the full risk management policy options, of which the GHG mitigation policy options are only a sub-set of 10 out of 150 options. In order to identify the impacts attributable to the GHG mitigation policy options alone, the proportion of production costs that are driven by the GHG mitigation measures compared to the full risk management measures has to be applied.

5.2 Energy Modelling

In this part of the study, estimates of the EU shale gas resource base and costs of shale gas production were made. These were then used to generate a set of play level 'supply curves'. A supply curve is a representation of the cumulative volume of gas that is recoverable at a given wellhead gas price. These were customised to each Member State. Key inputs to the curves were the uptake rates of the different abatement technologies under the different scenarios.

The costs of shale gas production were then used as inputs to the POLES energy model, which was used to model energy market and price impacts of the policy options.

The POLES model simulates demand and supply dynamically and gas prices are an endogenous result of the annual demand/supply equilibrium. As a result, a study of shale gas production and production costs will result in different gas prices overall; in turn, this will change the competitiveness of gas as a fuel to energy consumers. Thus, forecasts of shale gas production levels associated with variants on technology costs or policies in producing countries

will also be associated with corresponding forecasts of gas prices and gas demand levels by sectors in consuming countries.

For full details of the methodology please refer to the final report for the DG ENV study "Macroeconomic Impacts of Shale Gas Extraction in the EU".

Table 12 Uptake rates of GHG mitigation technologies under different policy scenarios

Technology	Methane Savings per Well	CapEx (€/ well)[47]	O&M (€/ year/ well)	Payback period	Uptake rates (%)		
					0. Base case	2. Less Stringent Policy	1. More Stringent Policy
Reduced emissions completions	208 t/ well	€22,856	0	One week	50	70	90
Install vapor recovery units on storage tanks	120 t/ year	€3,436	€708	13.5 months	10	30	50
Install plunger life systems in gas wells	88[48] t/ year	€3,730	€769	3.5 months	15	20	25
Replace wet seals in centrifugal compressors	9 t/ year	€2,492	€108	18 months	40	65	90
Conduct directed inspection and maintenance (Directed Leak Inspection and Measurement)	7 t/ year[49]	€0	€273	>12 months	10	35	60
Install flash tank separators in dehydrators	6 t/ year	€876	$0	9 months	10	55	100
Convert high bleed pneumatic devices	3 Mm^3/ year	€348	€0	8 months	40	60	80
Convert natural gas driven chemical pumps	2 t/ year	€380	€38.0	6 months	10	50	90
Rod packing replacement in reciprocating compressors	2 t/ year	€220	€0	2 months	40	70	100

[47] An exchange rate of 1.3 $/Eur has been used.

[48] The Natural Gas Star Lessons learned on plunger lifts reports average savings of 11,475 Mcf per well per year. Assuming that liquids unloading arises over the last four years of a well's life, the levelized methane savings can be computed as follows: 11,475*4/10 = 4,590 Mcf = 88 t^3.

[49] Assuming one leaking component per well.

5.3 Impacts on competitiveness and employment

5.3.1 Objectives and scope of assessment

It is clear that large-scale development of shale gas in Europe could have significant impacts on Europe's economies. For example, lower gas prices may lead to an increase in (real) incomes and provide the basis for future economic growth. The amount of investment needed to develop shale gas extraction is also likely to have substantial short-term impacts.

This chapter provides an assessment of the competitiveness and employment impacts of the shale gas risk management policy options in comparison to the base case. These risk management options have been developed in a separate DG ENV study "Macroeconomic Impacts of Shale Gas Extraction in the EU". The climate mitigation options for reducing fugitive methane emissions from shale gas extraction and production represent a sub-set of the risk management options. The final part of this section apportions the results to only the climate mitigation policy options.

The analysis is carried out at a sectoral level, recognising that there could be quite important distributional effects as well as macro-level impacts.

5.3.2 Modelling approach model details, data sources

Impacts on competitiveness and employment are based on the results of the market impact analysis from the POLES model. The E3ME macroeconomic model will convert key outputs from the POLES model (energy consumption (by fuel and sector), source of energy (i.e. domestic or imported), energy prices (by fuel) and investment by the energy sector into impacts on:

- GDP
- Employment by sector
- Unemployment
- Other macroeconomic indicators: Household incomes (by income group), Consumption, Investment, Government expenditure, Inflation
- Sectoral indicators: Output, Exports, Imports, Prices

The model is based on Eurostat data, with a historical database covering the period 1970-2010 (1995-2010 for CEE countries). Energy balances are obtained from the IEA. As macroeconomic models require a complete data set, gaps in the data have been estimated using customised software algorithms. To ensure that the analysis is carried out on a consistent basis, E3ME has been calibrated to the same baseline forecast as the POLES model. The labour market baseline forecast in E3ME will be calibrated to be consistent with the most recent version of the EU projections published by CEDEFOP.

5.3.3 Results

For full details of the results please refer to the final report for the abovementioned DG ENV study. This section presents summary results only.

Table 13 provides a summary of key economic indicators of the risk management options in 2030, for EU27, as a percentage difference from the base case. The table illustrates that the policy options represented by Scenario 1 and Scenario 2 have a negligible economic impact compared to the base case. At all levels the results for these scenarios are negligible because the policies have almost no impact on energy production, energy prices or energy demand (and therefore, no impact on the economy is observed).

Table 13 EU-27 Summary of impacts of economic and social impacts of risk management policy options (% difference from base case)

	0 - Base case	1 - More Stringent Policy	2 - Less Stringent Policy
GDP	0	-0.02	-0.01
Employment	0	0	0
Extra-EU Export	0	0	0
Extra-EU Import	0	0.07	0.04
Household Consumption	0	0	0
Investment	0	-0.01	-0.01
Unemployment	0	0.02	0.02

Table 14 shows the apportionment of the results to just the economic and social impacts of climate mitigation policy options. As these are a sub-set of the full risk management policy options and as they generate savings (due to value of recovered methane), the magnitude of the impacts is smaller but the direction of the impacts changes:-17% of costs of risk management options under Scenario 1 (stringent legislation); and -30% of costs of risk management options under Scenario 2 (medium legislation).

Table 14 EU-27 Summary of impacts of economic and social impacts of climate mitigation policy options (% difference from base case)

	0 - Base case	1 - More Stringent Policy	2 - Less Stringent Policy
GDP	0	<0.01	<0.01
Employment	0	0	0
Extra-EU Export	0	0	0
Extra-EU Import	0	-0.01	-0.01
Household Consumption	0	0	0
Investment	0	<0.01	<0.01
Unemployment	0	-<0.01	-<0.01

As above, the table illustrates the policy options represented by Scenario 1 and Scenario 2 have a negligible economic impact compared to the base case. At all levels the results for these scenarios are negligible because the policies have almost no impact on energy production, energy prices or energy demand (and therefore, no impact on the economy is observed).

5.4 GHG emissions impact assessment

5.4.1 Objectives and scope of assessment

This section aims to establish the impacts on emissions of greenhouses gases (GHG) that the different policy options will have.

The policy scenarios are expected to lead to three impacts on GHG emissions. The three impacts are listed in the table below, together with an indication for how the impacts are influenced by underlying assumptions.

Table 15 Impacts on GHG emissions

Impact	Affected by shale gas production projections	Affected by impact of GHG mitigation measures in capturing fugitive methane
Difference in fugitive GHG emissions from shale gas extraction and production (fugitive methane and CO_2 from flaring)	✓	✓
Difference in energy related CO_2 emissions that are associated with shale gas extraction and production	✓	
Difference in CO_2 emissions released from fuel combustion (shale gas and other downstream fuels)	✓	

In line with the impact assessment guidelines, we have aimed to:

- estimate whether the policy scenarios will lead to changes in emissions of carbon dioxide or other greenhouse gases;
- combine quantitative estimates of GHG emissions impacts using their comparative global warming potentials to estimate CO_2 equivalent impacts.

As per the inception report, we have not undertaken the step of monetising the estimated emission impacts (which would otherwise be valued using a forecast carbon price as a proxy for the social cost of carbon).

5.4.2 Modelling approach, model details, data sources

ESTIMATION OF FUGITIVE EMISSIONS

The estimates of fugitive emission releases of methane and of CO_2 emissions associated with flaring at the shale gas extraction sites have been made by:

1. Taking the estimates of technically recoverable shale gas resources for each EU27 Member State.

2. Estimating the number of well completions per year per Member State. In total for the EU27 this is estimated to be approximately 1000 wells per year by 2030 (see table below).

Table 16 Estimated well completions per year in reference scenario in EU-27

Annual well completions			
2015	2020	2025	2030
86	674	795	989

3. Estimating the number of wells remaining in operation in any given year, by assuming survival rates of wells. As a function of the age of the well, the percentage of wells that are assumed to remain functional are as shown in Figure 1 below, and the resulting operational wells are shown in the table below.

Figure 1 Survival curve for age of well operation

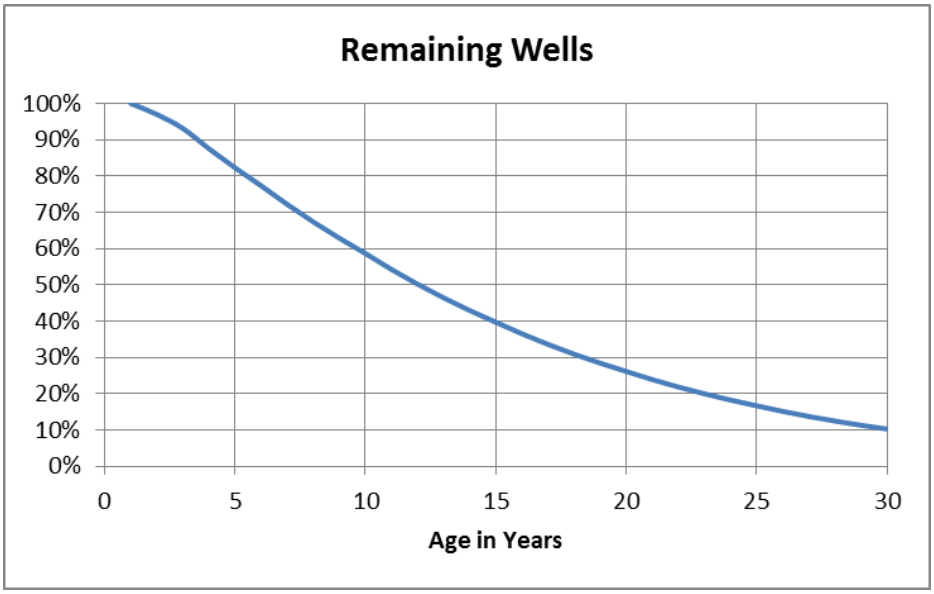


Table 17 Estimated number of wells in operation per year in reference scenario in EU-27

Number of wells in operation			
2015	2020	2025	2030
159	2,576	5,061	8,028

4. Estimation of the shale gas production per well production from the total production divided by the operational wells. These outputs are reproduced in the table below.

Table 18 Per-Well Production in million cubic metres per well per year

Member State	Production (million m^3/well/yr)			
	2015	2020	2025	2030
Austria	10	8	7	6
Bulgaria		9	7	7
Denmark		9	7	7
Estonia		7	5	5
France		9	7	6
Germany	9	8	6	6
Hungary	9	9	7	7
Ireland		8	7	7
Latvia		6	5	5
Netherlands	10	9	7	6
Poland	10	9	7	7
Romania		7	6	5
Spain	10	8	7	6
Sweden	9	7	5	5
United Kingdom	9	8	7	7

5. Fugitive methane emissions were estimated by calculating emission factors for key shale gas methane emission sources on a per producing well basis with the exception of methane emissions during a gas well completion, which were calculated on a per completed well basis. The calculated emission factors are shown in the table below.

Table 19 Methane Emission Factors (nominal well of 62 million m^3 estimated ultimate recovery)

Methane Emissions Source	Methane Emissions (t/ well / year)	Mitigation Technology
Gas Venting during Hydraulic Fracturing Completion Flowback	208	Reduced Emission Completions
Equipment Leaks	7	Directed Inspection & Maintenance
Natural Gas Pneumatic Pumps	2	Install Electric Pumps
Liquids Unloading	88	Install Plunger Lift

Methane Emissions Source	Methane Emissions (t/ well / year)	Mitigation Technology
Glycol Dehydrator Reboiler	6	Install Flash Tank Separator
Pneumatic Device Venting	3	Low Bleed Pneumatic Device Retrofit/Replacement
Reciprocating Compressor Rod Packing Leakage	2	Rod Packing Replacement
Storage Tank Venting	120	Vapor Recovery Unit
Centrifugal Compressor Wet Seal Degassing	9	Dry Seal
Centrifugal Compressor Wet Seal Degassing	9	Wet Seal Degassing Recovery System

6. For each Member State these emission factors were scaled up or down based on the average production per well.
7. The methane emission factors multiplied by the producing well counts and well completion counts discussed above yield the total unabated methane emissions from shale gas. Unabated methane emissions represent the absolute maximum methane emissions from shale gas without the implementation of any flaring or mitigation technologies.
8. The BAU case assumes some baseline adoption of each mitigation technology prior to any regulation. The medium and stringent regulation cases subsequently show higher adoption rates for each mitigation technology. These adoption rates were determined using expert judgment. The percentage of wells that have adopted each mitigation technology is shown in the table below for each regulatory scenario. In addition, the typical average methane recovery efficiency is also shown.

Table 20 Percentage of Wells that have Adopted each Mitigation Technology under Three Conditions

Mitigation Technology	0-Base case Uptake	1- More Stringent Policy Uptake	2 – Less Stringent Policy Uptake	Methane recovery efficiency
Reduced Emission Completions	50%	90%	70%	90%
Directed Inspection & Maintenance	10%	60%	35%	100%
Install Electric Pumps	10%	90%	50%	100%
Install Plunger Lift	15%	25%	20%	100%
Install Flash Tank Separator	10%	100%	55%	95%
Low Bleed Pneumatic Device Retrofit/Replacement	40%	80%	60%	84%
Rod Packing Replacement	40%	100%	70%	55%
Vapor Recovery Unit	10%	50%	30%	95%
Dry Seal	40%	90%	65%	97%
Wet Seal Degassing Recovery System	0%	10%	5%	99%

9. Under the base case and scenarios 1 and 2, flaring is assumed to occur on all completed wells that do not implement Reduced Emission Completions (RECs). Flares are assumed to have a 95 percent combustion efficiency.

ESTIMATION OF ENERGY RELATED CO_2 EMISSIONS ASSOCIATED WITH SHALE GAS EXTRACTION AND PRODUCTION AND OF COMBUSTION RELATED CO_2 ASSOCIATED WITH DOWNSTREAM FUELS

The scenarios that have been modelled in POLES include all 150 risk management measures. However, in order to estimate the impacts of just the 10 GHG mitigation measures in isolation, an interpretative adjustment is necessary to the POLES modelling results in order to estimate the impact of the GHG mitigation measures in isolation. On the basis that the primary driver for changes in shale gas production levels is the shale gas production costs, this isolating adjustment has been undertaken by running the cost model with only the 10 GHG mitigation measures, identifying the difference in costs between the policy options and the base case, and dividing these differences by the cost model results for all 150 measures. This gives an estimate for the fraction that represents the proportion of the delta going from the base case to the scenarios that is attributable to just the GHG measures.

This factor based approach has been undertaken for estimating both the energy related CO_2 emissions associated with shale gas extraction as well as the combustion related CO_2 emissions associated with downstream fuel consumption.

This approach produces negative and small factors which indicate that the GHG mitigation measures in isolation produce a small benefit in terms of a monetary saving (due to the value of recovered methane outweighing the costs of the technology), but which is dominated by a large cost from the remaining risk management measures. The factors are

- -17% of the POLES model deltas from the base case to Scenario 1 (more stringent policy) are attributable to the GHG mitigation measures; and
- -30% of the POLES model deltas from the base case to Scenario 2 (less stringent policy) are attributable to the GHG mitigation measures.

The estimation of the energy related CO_2 emissions associated with shale gas extraction has utilised sectoral outputs of CO_2 emissions from POLES, in the category Other Transformation, and which has been calculated as a separate line as “of which from inputs for shale gas production”.

5.4.3 Results

RESULTS

The emissions of fugitive methane and CO_2 emissions from flaring are shown in the table below. After taking into account the relative global warming potential of CH_4 to CO_2, the fugitive methane emissions are significantly more important to consider than the CO_2 emissions from flaring.

Table 21 below shows the estimated fugitive methane emissions for EU27 under the different scenarios.

Table 22 below shows both the estimated fugitive methane emissions (expressed as CO_2e) and the estimated CO_2 emissions from flaring, and their combined total as CO_2e (assuming a global warming potential for methane of 21) for the EU-27.

Table 21 Projections of fugitive methane emissions from shale gas extraction and production at EU-27 level (kt/yr)

Year	Unabated	0. Base case	1. More Stringent Policy	2. Less Stringent Policy
2015	82	50	34	42
2020	1,080	771	489	620
2025	1,954	1,501	905	1,142
2030	3,011	2,368	1,418	1,794

Table 22 Estimated GHG emissions (kt CO_2) per scenario from fugitive sources

Shale gas extraction and production source	Year	Absolute emissions per scenario (kt CO2e)				Absolute emissions difference from base case (kt CO2e)			
		Unabated	0. Base case	1. More Stringent Policy	2. Less Stringent Policy	Unabated	0. Base case	1. More Stringent Policy	2. Less Stringent Policy
Methane emissions from fugitive sources	2015	1,717	1,043	722	888	673	0	-321	-156
	2020	22,674	16,187	10,279	13,018	6,487	0	-5,909	-3,169
	2025	41,042	31,520	19,006	23,972	9,523	0	-12,514	-7,547
	2030	63,239	49,722	29,774	37,675	13,517	0	-19,948	-12,047
CO_2 emissions from flaring from fugitive sources	2015	0	34	7	21	-34	0	-27	-13
	2020	0	264	47	144	-264	0	-217	-120
	2025	0	307	53	154	-307	0	-254	-153
	2030	0	384	68	209	-384	0	-316	-175
Total GHG emissions from fugitive sources	2015	1,717	1,077	729	908	+639	0	-348	-169
	2020	22,674	16,451	10,326	13,163	+6,222	0	-6,126	-3,289
	2025	41,042	31,827	19,059	24,126	+9,216	0	-12,768	-7,700
	2030	63,239	**50,106**	29,842	37,885	**+13,134**	0	**-20,264**	**-12,221**

The results for the energy related CO_2 emissions from the production of shale gas are shown below. The results show that the estimated impact on energy related CO_2 emissions of the GHG mitigation options among different policy scenarios is negligible compared to the absolute values of fugitive emissions.

Table 23 Estimated GHG emissions (kt CO_2) per scenario from energy related CO_2 emissions associated with fuel extraction and production

Shale gas extraction and production source	Year	Absolute emissions per scenario attributable to all risk mitigation measures (kt CO_2)			Absolute emissions difference from BAU attributable to all risk mitigation measures (kt CO_2)			Absolute emissions difference from BAU attributable to GHG mitigation measures only (kt CO_2)		
		0. Base case	1. More Stringent Policy	2. Less Stringent Policy	0. Base case	1. More Stringent Policy	2. Less Stringent Policy	0. Base case	1. More Stringent Policy	2. Less Stringent Policy
Energy related O_2 emissions from shale gas production	2015	0.2	0.2	0.2	0	0	0	0	0	0
	2020	213	211	212	0	-3	-1	0	0	0
	2025	353	340	346	0	-13	-8	0	2	2
	2030	514	480	491	0	-34	-22	0	6	7

Note that the small positive change in GHG emissions under the policy scenarios attributable to GHG mitigation measures is due to their effect of reducing production costs (due to value of recovered methane outweighing the costs of the technology), increasing the amount of production and hence increasing production related emissions.

The results for the CO_2 emissions from combustion of the resulting fuel mix are shown below. The results show that the estimated impact on combustion related CO_2 emissions of the GHG mitigation options among different policy scenarios is negligible compared to the GHG emission differences among policy options for fugitive emissions.

Table 24 Estimated CO_2 emissions (note units differ across table) per scenario from combustion of energy mix

Downstream sector	Year	Absolute emissions per scenario attributable to all risk mitigation measures (Mt CO_2)	Absolute emissions difference from BAU attributable to GHG mitigation measures only (kt CO_2)	
		0. Base case	1. More Stringent Policy	2. Less Stringent Policy
Electricity generation	2015	1241	0	0
	2020	1040	0	0
	2025	818	0	0
	2030	691	-1	0
Industry	2015	484	0	0
	2020	451	0	0
	2025	405	0	0
	2030	347	0	0

Downstream sector	Year	Absolute emissions per scenario attributable to all risk mitigation measures (Mt CO_2)	Absolute emissions difference from BAU attributable to GHG mitigation measures only (kt CO_2)	
		0. Base case	1. More Stringent Policy	2. Less Stringent Policy
Residential	2015	605	0	0
	2020	578	0	0
	2025	512	0	0
	2030	434	-1	-1
Total	2015	2330	0	0
	2020	2068	0	0
	2025	1735	0	0
	2030	1472	-2	-2

The combined results for fugitive methane emissions, CO_2 emissions from flaring, energy related CO_2 emissions from shale gas production and CO_2 emissions from combustion of the changing energy mix show the following breakdown:

Table 25 Relative impact of different GHG components on difference in emissions between scenario 1 and base case

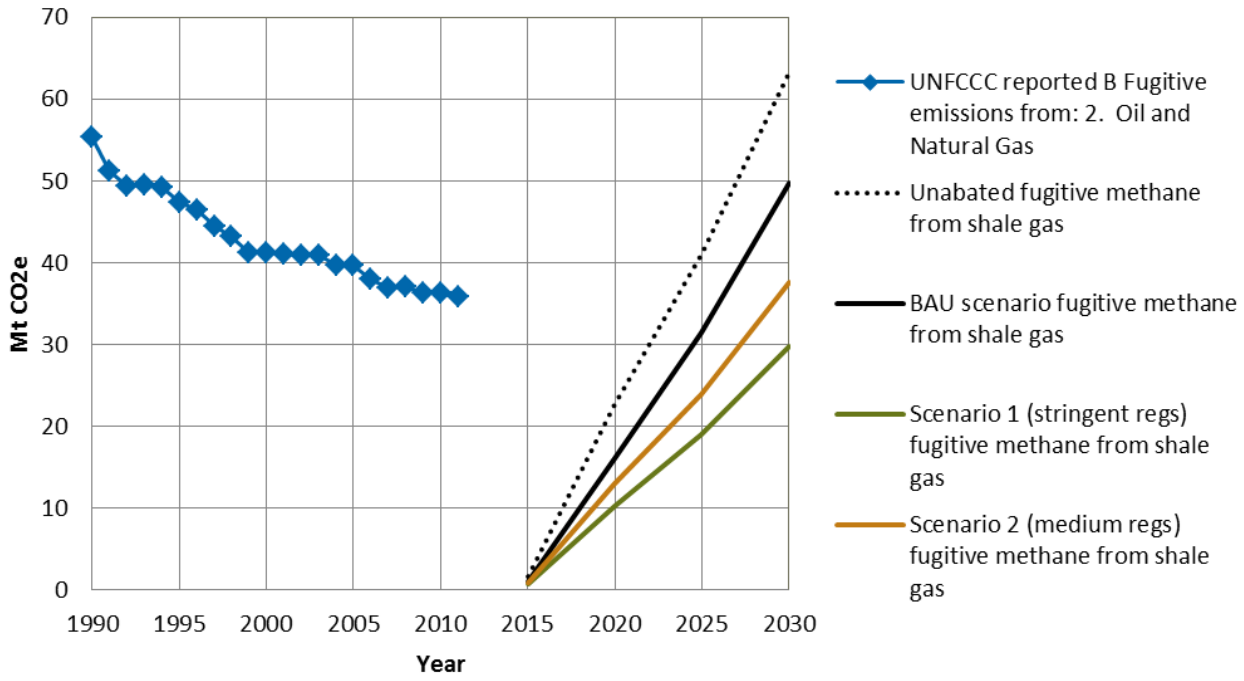
GHG component	% contribution in 2030 to difference of Scenario 1 compared to base case
Fugitive methane emissions from shale gas production and extraction	98.46%
CO_2 emissions from flaring at shale gas production and extraction	1.56%
Energy related CO_2 emissions at shale gas production and extraction	-0.03%
Combustion related CO_2 emissions from downstream energy mix changes	0.01%

INTERPRETATION

The fugitive methane emissions component is the largest and most important GHG impact among the scenarios.

The absolute emissions of fugitive methane from shale gas production is estimated to increase considerably from the low shale gas extraction in 2015 associated with 0.05Mt CH_4 to the assumed 2030 activity levels that are associated with 2.4Mt CH_4 under BAU scenario. The 2011 EU27 methane emissions[50] from fugitive releases from oil and natural gas are reported to be 1.7Mt, having declined from 2.6Mt in 1990. The fugitive emissions from shale gas as estimated here would not necessarily be additional to the existing figures if conventional natural gas production in the EU declined in compensation to increasing shale gas production. But if the shale gas production and consumption displaced imported natural gas consumed in the EU, then the fugitive methane emissions for the EU from the extraction of shale gas would be additional to the existing reported emissions (but from a global perspective may not be additional). Figure 2 plots together both the historical reported fugitive methane emissions from oil and natural gas and the estimated shale gas fugitive methane (in CO_2 equivalent) as unabated, BAU and medium and stringent regulation policy scenarios.

Figure 2 Historical EU27 reported fugitive methane emissions declined from 1990 to 2011. Estimated fugitive methane emissions from shale gas are projected to be large and grow significantly in comparison



Source for historical data: footnote 50; source for future data: this work.

The unabated fugitive emissions that have been estimated are directly correlated with shale gas production levels. To this extent the increase over time in the fugitive emissions reflects the increasing shale gas production volumes.

The estimates of the impacts of the policy options on GHG emissions are subject to uncertainty caused by uncertainty in at least the following factors:

[50] National emissions reported to the UNFCCC and to the EU Greenhouse Gas Monitoring Mechanism, collated at : http://www.eea.europa.eu/data-and-maps/figures/ds_resolveuid/c3ed87a3b331414a90053bd00778334c

- Unabated emissions factors
- Abatement efficiency of climate mitigation measures
- Uptake of climate mitigation measures under BAU scenarios
- Requirements for additional uptake of climate mitigation measures under policy scenarios and responses to these requirements
- Projections of numbers of wells per MS and their characteristics
- Scale up of emissions per well to emissions per MS.

5.4.4 Summary

The most important GHG impact of shale gas production changes are fugitive methane emissions. The policy scenarios 1 and 2 (of more stringent and less stringent policy respectively) suggest reduction in fugitive methane emissions from the base case of 35% to 40% and 20% to 25% respectively for the years 2020 and 2030.

5.5 Impacts on air pollutant emissions and ambient air quality

5.5.1 Objectives and scope of assessment

The objective of this section is to consider what air pollutant emissions might be associated with fugitive methane emissions from shale gas extraction; what might be the impact on these emissions of climate mitigation measures for fugitive methane; and what are the existing EU policies that can protect human health and the environment from these emissions.

5.5.2 Assessment approach

EMISSIONS

Fugitive methane emissions from shale gas extraction will be associated with small concentrations of a range of other VOCs and compounds specific to the particular hydrocarbon resources of the shale gas play in question.

Many of these compounds may be ‘Hazardous Air Pollutants’, a term used by US EPA to cover toxic air pollutants that cause or may cause cancer or other serious health effects, or adverse environmental and ecological effects. Based on our experience of undertaking Environmental Impact Statements (EIS) for shale gas developments in the USA, key hazardous species that may be associated with methane are listed in the table below. This also indicates their relative emissions factor compared to methane based on ICF emissions factor data or examination of selected EIS data.

Table 26 Key hazardous species that may be associated with methane

Hazardous air pollutant	Relative emissions factor compared to methane (=1.0)
Acetaldehyde	No information
Acrolein	No information
Benzene	0.00029
Ethyl benzene	An order of magnitude lower than benzene

Formaldehyde	Between same order of magnitude as benzene and an order of magnitude higher
n-Hexane	Between same order of magnitude as benzene and an order of magnitude higher
Hydrogen sulphide	0.05184
Methanol	No information
Toluene	0.00021
Xylene	Same order of magnitude as benzene

Methane and other volatile organic compounds (VOCs) are also precursors to the formation of ozone, which is associated with a range of morbidity effects (related to respiratory conditions) as well as increased mortality.

IMPACTS OF CLIMATE MITIGATION MEASURES

The climate mitigation measures identified in this study are assumed to achieve broadly the same abatement efficiency of the abovementioned air pollutants as methane. This is because they operate by physical capture and separation and the compounds have broadly similar physical properties.

As such, climate mitigation measures will result in co-benefits of reductions in air pollutant emissions. For those species for which emissions factors relative to methane can be estimated, the impact of the policy options is summarized in the table below.

Table 27 Estimated impact on selected air pollutant emissions across the EU of climate mitigation measures assumed to be implemented under the policy options

Fugitive air pollutant emissions from shale gas extraction and production	Year	Absolute emissions per scenario (t)				Relative emissions difference from base case		
		Unabated	0. Base case	1. More Stringent Policy	2. Less Stringent Policy	Unabated	1. More Stringent Policy	2. Less Stringent Policy
Benzene	2015	24	15	10	12	65%	-31%	-15%
	2020	316	226	143	182	40%	-37%	-20%
	2025	573	440	265	335	30%	-40%	-24%
	2030	883	694	416	526	27%	-40%	-24%
Toluene	2015	17	10	7	9	65%	-31%	-15%
	2020	224	160	102	129	40%	-37%	-20%
	2025	405	311	188	237	30%	-40%	-24%
	2030	625	491	294	372	27%	-40%	-24%
H_2S	2015	4,238	2,576	1,783	2,191	65%	-31%	-15%

Fugitive air pollutant emissions from shale gas extraction and production	Year	Absolute emissions per scenario (t)				Relative emissions difference from base case		
		Unabated	0. Base case	1. More Stringent Policy	2. Less Stringent Policy	Unabated	1. More Stringent Policy	2. Less Stringent Policy
	2020	55,970	39,958	25,372	32,136	40%	-37%	-20%
	2025	101,312	77,806	46,915	59,175	30%	-40%	-24%
	2030	156,105	122,737	73,497	93,001	27%	-40%	-24%

The climate mitigation measures will also reduce ozone concentrations in locations where ozone formation is VOC limited.

RELEVANT EU AIR QUALITY LEGISLATION

Relevant air quality limit values in the EU Air Quality Directive (Directive 2008/50/EC) for air pollutant emissions from shale gas extraction and production include:

- Benzene: 5 µg/m^3 (annual mean)
- Ozone: 120 µg/m^3 (max daily 8 hour mean)

The benzene air quality limit value will also provide some controls over concentrations of other VOCs given that the abatement measures necessary to control benzene will also control the other VOCs.

It is not within the scope of this study to undertake air quality modeling in the vicinity of potential shale gas extraction and production facilities in the EU. However, a brief review was undertaken of some EISs of shale gas facilities in the US including the following:

- GASCO / Uinta Basin, Utah
  - 1491 natural gas wells
  - 21 tonnes benzene emissions from operational phase (data not available for drilling and construction phase), mostly assumed to be fugitive emissions
  - Other hazardous air pollutant emissions (mostly assumed to be fugitive emissions)
    - 2 t ethyl benzene
    - 11t formaldehyde
    - 33t n-hexane
    - 43t toluene
    - 30t xylene
  - 0.3 µg/m^3 benzene ground level concentration at a location 100m from the site boundary
- Continental-Divide Creston (CD-C), Wyoming
  - 8950 natural gas wells
  - 86 tonnes benzene emissions from operational phase (data not available fo
  - r drilling and construction phase), mostly assumed to be fugitive emissions
  - Other hazardous air pollutant emissions (mostly assumed to be fugitive emissions)
    - 4t ethyl benzene

    - 550t formaldehyde
    - 400t n-hexane
    - 120t toluene
    - 61t xylene
  - 0.2 µg/m^3 benzene ground level concentration at a location 100m from the site boundary

This shows that, in these examples, the contribution of operational activities at shale gas extraction and production facilities to ground level concentrations of benzene 100m from the site boundary is less than 10% of the EU air quality limit value for benzene.

Given the multitude of site specific factors influencing air quality compliance it is not possible, however, to draw any conclusions from the above examples to the EU.

5.5.3 Summary

The climate mitigation policy options should act to reduce emissions and concentrations of these compounds and hence provide human health and environmental co-benefits. Our assessment has developed estimations of reductions in EU-wide emissions of 3 key toxic compounds for which emissions factor data was available, namely benzene, toluene and hydrogen sulphide. Estimates illustrate that Scenario 1 could lead to emissions reductions in 2020 and 2030 within the range of 35% to 40% for all three air pollutants, compared to the base case, and Scenario 2 could lead to reductions within the range of 20% to 25%.

5.6 Assessment of policy options

This study has investigated the following scenarios related to potential risk management policy options for mitigation of fugitive GHG impacts of possible future shale gas extraction in the EU:

0. **Base case**, with 'business as usual' (BAU) assumptions applied for the EU-27 shale gas resource base, world economic growth and relevant climate / environmental policies.
1. Adoption of new, **more stringent shale gas risk management policies.** This includes the elaboration of specific EU framework for shale gas, or an amendment to the Industrial Emissions Directive (IED).
2. Adoption of **less stringent shale gas risk management policies (relative to scenario 1).** This includes promotion of an EU-level voluntary approach to minimise fugitive GHG emissions (including industry standards), or an amendment to the EIA Directive.

In all scenarios, the exposition of the EU to international markets and the relatively small volumes of shale gas compared to conventional gas production and gas imports is such that the differences in costs of domestic shale gas production caused by the policy scenarios have little effect on global supply and thus on international gas prices. As a result, prices between scenarios do not change.

The following table shows the summary of the key economic, social and environmental impacts of the climate mitigation policy scenarios, compared to the base case scenario.

Table 28 EU-27 Summary of economic, social and environmental impacts of climate mitigation policy options (% and absolute difference from base case)

Type of impact	Year[51]	0-Base case		1. More Stringent Policy		2. Less Stringent Policy	
Basis		**%**	**Absolute**	**%**	**Absolute**	**%**	**Absolute**
Economic and social impacts							
GDP	2030	0		<0.01		<0.01	
Employment	2030	0		0		0	
Extra-EU Export	2030	0		0		0	
Extra-EU Import	2030	0		-0.01		-0.01	
Household Consumption	2030	0		0		0	
Investment	2030	0		<0.01		<0.01	
Unemployment	2030	0		-<0.01		-<0.01	
Environmental impacts							
GHG emissions[52]	2020	0	16,451 kt CO_2e	-37	10,326 kt CO_2e	-20	13,163 kt CO2e
	2030	0	50,106 kt CO_2e	-40	29,842 kt CO_2e	-24	37,885 kt CO_2e
Air pollutant emissions[53]							
• Benzene	2020	0	226t	-37	143t	-20	182t
	2030	0	694t	-40	416t	-24	526t
• Toluene	2020	0	162 0t	-37	103t	-20	129t
	2030	0	491t	-40	298t	-24	372t
• Hydrogen sulphide	2020	0	39,958t	-37	25,372t	-20	32,136t
	2030	0	122,737t	-40	73,497t	-24	93,001t

This table illustrates that the climate mitigation policy options represented by Scenario 1 and Scenario 2 have a negligible economic impact compared to the base case, because the policies have a negligible impact on energy production, energy prices and energy demand. This is due to the modest impact of the policy options on shale gas production costs. The capital costs and annual operating costs of climate mitigation measures associated with reducing fugitive methane emissions are more than offset by the annual revenue from recovered methane.

The climate mitigation policy options are estimated to result in reductions of EU fugitive methane emissions from shale gas extraction and production in 2020 and 2030 of 35% to 40%

[51] Note that economic and social impacts are only presented for 2030 due to their very small magnitude.

[52] Fugitive methane emissions from shale gas extraction and production and CO_2 emissions from flaring from shale gas extraction and production. In addition there is a relatively very small quantity of CO_2 emissions impacts associated with impacts on shale gas production levels (energy related CO_2 associated with fuel extraction and production and CO_2 from combustion of fuels in the downstream sectors).

[53] Fugitive methane emissions from shale gas extraction will be associated with small concentrations of a range of other VOCs and compounds specific to the particular hydrocarbon resources of the shale gas play in question. Many of these compounds may be 'Hazardous Air Pollutants' (HAPs), a term used by US EPA to cover toxic air pollutants that cause or may cause cancer or other serious health effects, or adverse environmental and ecological effects. The results are presented for HAPs for which emissions factor data was available. Overall, climate mitigation measures are expected to have a similar percentage mitigation effect on HAPs emissions.

for Scenario 1 and 20% to 25% for Scenario 2, compared to base case emissions. These represent by far the most dominant source of GHG impacts of the policy options.

Fugitive methane emissions are likely to be associated with small concentrations of Hazardous Air Pollutants (HAPs) which will also be reduced by the climate mitigation policy options to a similar degree as methane. The estimates of impacts on shale gas emissions and production costs can be affected by uncertainties in emissions factors; abatement efficiencies of mitigation measures; capital and operating costs of mitigation measures; gas prices; uptake of measures under the base case; requirements for additional uptake of measures under policy scenarios; projections of numbers of wells per MS and their characteristics and scale up of emissions per well to emissions per MS.

Further sources of uncertainty relate to the energy and economic modeling, which can be affected by uncertainties in the data and assumptions, simulation methods and modeling relationships, baseline forecasts and model/scenario assumptions.

Whilst for a single parameter or equation it is possible to produce a formal statistical estimate of uncertainty in the results there is no feasible equivalent test for a set of modelling results. However, when comparing the differential impacts between the policy scenarios and the base case, uncertainties will tend to cancel out and become less important. As such, the comparative results from this analysis are considered to provide a robust basis for comparing the policy options.

Appendix A - International case study tables from Task 1

United States Federal Government – Natural Gas STAR Program

Aspect	Details
Name of policy / programme	Natural Gas STAR Program
Responsible authority	United States Environmental Protection Agency
Date policy/ programme adopted	The Natural Gas STAR program was established in 1993[54]. The program partnered with U.S. partners in the early years. In 2006 the program expanded and began partnering with international oil and gas companies.
Objectives	Natural Gas STAR is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt proven, cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. [55]
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	The methane emissions from the oil and natural gas sector account for 37% of methane emissions in the United States or 3.8% of the total greenhouse gas emissions in the United States. Methane's global warming potential is 25 times that of CO_2. This fact coupled with the economic benefits of capturing methane from the oil and natural gas sector has led to the creation of the Natural Gas STAR Program.
Key drivers	Public health and the potential economic benefits to producers from methane capture.
Which on-site GHG fugitive emissions covered?	The program provides cost-effective methane emission reduction technologies and practices for the following emission sources:, 1. Compressors/Engines 2. Dehydrators 3. Pipelines 4. Pneumatics/Controls 5. Tanks 6. Valves 7. Wells 8. Leaks

[54] Background: Global Methane initiative and Natural Gas International, United States EPA, p.1 http://www.epa.gov/gasstar/documents/int_fs.pdf

[55] Natural Gas STAR Website: http://www.epa.gov/gasstar/basic-information/index.html, accessed, 02/11/2013.

Aspect	Details
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	There are no requirements, all reductions are voluntary. The following GHG minimisation technologies are recommended: For compressors/engines, the following mitigation technologies are recommended: 1. Replace Gas Starters with Air or Nitrogen 2. Reduce Natural Gas Venting with Fewer Compressor Engine Startups and Improved Engine Ignition 3. Reducing Methane Emissions from Compressor Rod Packing Systems 4. Test and Repair Pressure Safety Valves 5. Reducing Emissions When Taking Compressors Off-Line 6. Eliminate Unnecessary Equipment and/or Systems 7. Install Automated Air/Fuel Ratio Controls For dehydrators, the following mitigation technologies are recommended: 1. Reroute Glycol Skimmer Gas 2. Pipe Glycol Dehydrator to Vapor Recovery Unit 3. Replace Glycol Dehydration Units with Methanol Injection 4. Portable Desiccant Dehydrators 5. Eliminate Unnecessary Equipment and/or Systems 6. Zero Emissions Dehydrators 7. Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators For pipelines, the following mitigation technologies are recommended: 1. Test and Repair Pressure Safety Valves 2. Insert Gas Main Flexible Liners 3. Composite Wrap for Non-Leaking Pipeline Defects 4. Perform Valve Leak Repair During Pipeline Replacement 5. Using Hot Taps for In Service Pipeline Connections 6. Recover Gas from Pipeline Pigging Operations 7. Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance For pneumatic controls, the following mitigation technologies are recommended: 1. Convert Gas Pneumatic Controls to Instrument Air 2. Convert Pneumatics to Mechanical Controls 3. Convert Natural Gas-Driven Chemical Pumps 4. Replacing Gas-Assisted Glycol Pumps with Electric Pumps For tanks, the following mitigation technologies are recommended: 1. Convert Water Tank Blanket from Natural Gas to Produced CO2 Gas 2. Installing Vapor Recovery Units on Storage Tanks For wells, the following mitigation technologies are recommended: 1. Test and Repair Pressure Safety Valves 2. Connect Casing to Vapor Recovery Unit 3. Installing Plunger Lift Systems in Gas Wells 4. Install Compressors to Capture Casinghead Gas 5. Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells To address leaks, the following mitigation technologies are recommended:

Aspect	Details
	1. Directed Inspection and Maintenance at Compressor Stations 2. Test and Repair Pressure Safety Valve
How were these requirements set? When reviewed and at what frequency?	There are no emission reduction requirements, all emission reductions are voluntary.
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	There are no monitoring requirements. However; if partners adopt any emission reduction projects, then they are required to report the methane emission reductions associated with those projects.
Notification, reporting and verification requirements	If partners adopt any emission reduction projects, then they are required to report the methane emission reductions associated with those projects. The EPA maintains the results of the methane emission reductions in a confidential database.
Compliance enforcement / sanctions	None
What measures are shale gas extraction/production companies expected to implement to respond?	When economically feasible, the following emission measure may be implemented to deal with well completion emissions from hydraulically fractured natural gas wells: 1. Reduced emissions completions (RECs) 2. Energized fracturing reduced emissions completions 3. Compression based reduced emissions completions
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)	**Purchased reduced emissions completions equipment annual program**[56] Implementation cost: $500,000, other costs: $121, 250 per year **Incremental reduced emissions completions contracted service** Implementation cost: $32,400, other costs: $600 per year
Emission reductions achieved (as a % of on-site fugitive methane emissions)	The **Domestic** program achieved annual methane emission reductions of 94 Bcf in 2010. Cumulative program methane emission reduction between 1993 and 2010 are equal to 994 Bcf.[57]

[56] Lessons Learned: Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, EPA, p.1. http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf

[57] Natural gas star website: http://www.epa.gov/gasstar/accomplishments/index.html

Aspect	Details
Extent to which objectives met	The program has more than 115 domestic (U.S) and international partners spanning the production, gathering and boosting, transmission and the distribution sectors (although not all shale gas). For calendar year 2010, nearly 80 percent of U.S. partners submitted an annual report detailing their efforts to reduce methane emissions from their operations. These voluntary activities consisted of nearly 100 technologies and practices and resulted in domestic emissions reductions of 2.66 billion cubic meters (94.1 Bcf) of methane? for the year. These methane emissions reductions have cross-cutting benefits on domestic energy supply, industrial efficiency, revenue generation, and greenhouse gas emissions reductions[58]

[58] http://www.epa.gov/gasstar/accomplishments/

United States Federal Government – New Source Performance Standard OOOO

Aspect	Details
Name of policy / programme	New Source Performance Standards Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution
Responsible authority	"The NSPS is developed and implemented by EPA and are delegated to the states. However, even when delegated to the states, EPA retains authority to implement and enforce the NSPS."[59]
Date policy/ programme adopted	Program signed on April 17th, 2012. The rule was published in the Federal Register on August 16th 2012.[60] The NSPS applies to facilities that are constructed, modified or reconstructed after August 23, 2011. Existing facilities that are subject to the rule had 60 days from the day the rule was published in the Federal Register to come into compliance.
Objectives	"The newly established NSPS for the Crude Oil and Natural Gas Production source category regulate volatile organic compound (VOC) emissions from hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and leaking components at onshore natural gas processing plants, as well as sulfur dioxide (SO2) emissions from onshore natural gas processing plants."[61] However, the same rules will also be effective at reducing emissions of methane and CO_2. Furthermore, the rule also sets cost-effective performance standards for: gas wells, storage vessels, certain controllers and certain compressors.
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	This rulemaking was prompted by a lawsuit filed by environmental organisations in January 2009, alleging that EPA had missed the statutory deadlines for reviewing and updating the NSPS and NESHAP standards for the oil and gas sector.[62] The rule revised some the older standards and introduced new standards for well completions, pneumatic devices and compressors.
Key drivers	**Public health:** Section 111(b) of the CAA requires EPA to issue "standards of

[59] EPA Website: http://www.epa.gov/compliance/monitoring/programs/caa/newsource.html, accessed, 02/12/2013.

[60] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Docket ID: EPA-HQ-QAR-2010-050. http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4574

[61] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Part 63, [EPA-HQ-OAR-2010-0505; FRL-], RIN 2060-AP76 http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf, Page 17 of 588.

[62] WRAP (2011) Analysis of States' and EPA Oil and Gas Air Emissions Control Requirements for Selected Basins in the Western United States. Available online here: http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20(01-08).pdf

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	performance" (known as NSPS) for categories of new and modified sources which EPA has determined cause, or contribute significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare. The NSPS must reflect the application of the "best system of emissions reductions" (BSER) that has been adequately demonstrated. The CAA requires review of NSPS every eight years. The existing NSPS for the oil and natural gas sector were issued in 1985, and regulate SO_2 and VOC emissions from natural gas processing plants. [63]
Which on-site GHG fugitive emissions covered?	The emission sources affected by the NSPS include[64]: 1. Gas well completions[65], 2. Pneumatic controllers, 3. Equipment leaks from natural gas processing plants, 4. Sweetening units at natural gas processing plants, 5. Reciprocating compressors, 6. Centrifugal compressors, 7. Storage vessels.
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	**Standards for Hydraulically Fractured Gas Wells.** "For fractured and refractured gas wells, the rule generally requires owners/operators to use reduced emissions completions, also known as "RECs" or "green completions," to reduce VOC emissions from well completions. To achieve these VOC reductions, owners and/or operators may use RECs or completion combustion devices, such as flaring, until January 1, 2015; as of January 1, 2015, owners and/or operators must use RECs and a completion combustion device. The rule does not require RECs where their use is not feasible, as specified in the rule." The final rule expressly excludes "low pressure gas wells" from the requirement to use REC technology. Whether a well qualifies as a low pressure well is determined based on the well's vertical depth, reservoir pressure, and the flow line pressure at the sales meter, using a prescribed equation. Low pressure gas wells, along with delineation wells and wildcat wells, will only be required to use a completion combustion device to control emissions during flowback. EPA estimates that this exclusion for low pressure gas wells will cover 10 percent of all natural gas wells and, specifically, 87 percent of coal-bed methane wells. **Standards for storage vessels.** The rule requires controls for new, reconstructed, and modified storage vessels that have VOC emissions equal to or greater than six tpy. New, reconstructed, and modified storage vessels with VOC emissions exceeding 6 tpy must have controls to reduce VOC emissions by 95% installed no later than one year after publication in the Federal Register. **Standards for compressors.** Centrifugal compressors with wet seals (that are built or modified after the date of the proposed rule) must achieve a 95% reduction in VOC emissions by using flaring or emission capture devices. Compressors with dry seals are not subject to the

[63] http://www.vnf.com/news-alerts-701.html

[64] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Part 63, [EPA-HQ-OAR-2010-0505; FRL-], RIN 2060-AP76 http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf, p.21

[65] Well completion is defined as the flowback period beginning after hydraulic fracturing and ending with either well shut in or when the well continuously flows to the flow line or to a storage vessel for collection, whichever occurs first.

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	NSPS. For reciprocal compressors, the final NSPS requires replacement of rod packing at regular intervals. **Standards for pneumatic controllers.** New and modified pneumatic controllers at natural gas processing plants must achieve zero emissions of VOCs; pneumatic controllers located between the wellhead and the transmission line must use "low bleed" designs after a one-year phase in period. **Leak detection and repair at natural gas processing plants.** The revised rule imposes more stringent leak detection and repair requirements for existing gas processing plants, to be phased in one year after the NSPS take effect. In addition, the rule requires more stringent SO_2 controls at "sweetening" units used to remove sulfur from natural gas.
How were these requirements set? When reviewed and at what frequency?	The requirements for this rule were set by the EPA with consultation of oil and natural gas producing companies. The EPA must review the rules every eight years.
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	Conditions of permitting for well completions. Reciprocating compressor affected sources must replace the rod packing either (1) before the compressor has operated 26,000 hours from initial startup or the last packing replacement; or (2) prior to 36 months from startup or the last rod packing replacement. **The first option requires continuous monitoring of the hours of operation**. Centrifugal compressors impacted by this regulation must reduce VOC emissions from each wet seal fluid degassing system by 95.0 percent or more. If using a control device, the system must be equipped with a cover and closed vent system. **Continuous compliance is demonstrated through inspections and parametric monitoring.** New, reconstructed, and modified storage vessels with VOC emissions exceeding 6 tpy must have controls to reduce VOC emissions by 95% installed no later than one year after publication in the Federal Register. If using a control device, the system must be equipped with a cover and closed vent system. **Continuous compliance for storage vessel is demonstrated through inspections and parametric monitoring.**
Notification, reporting and verification requirements	The rule provides a "streamlined notification process for well completions at gas well affected facilities consisting of an email pre-notification no later than 2 days in advance of impending completion operations. The email must include information that had been part of the 30-day advance notification, including contact information for the owner and operator, well identification, geographic coordinates of the well and planned date of the beginning of flowback."[66] Moreover, if the operator is required under applicable state law to provide advance notice of commencement of well completion operations, compliance with the state notice requirement will satisfy the

[66] http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf, page 43.

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	NSPS's advance notice requirement. "In the final rule, the recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation."[67]
Compliance enforcement / sanctions	Conditions of permitting. More specifically, the initial compliance period begins on October 15, 2012 or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year. To achieve initial compliance with the standards for each well completion operation conducted at a gas well affected facility, the operator must comply with the paragraphs below: **(1)** You must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format. **(2)** You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) of this section. The initial annual report is due 30 days after the end of the initial compliance period. (1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section. (i) The company name and address of the affected facility. (ii) An identification of each affected facility being included in the annual report. (iii) Beginning and ending dates of the reporting period.

[67] http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf, page 44.

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	(iv) A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. (2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section. (i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion. (ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period. (3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section. (i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period. (ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period. (iii) If required to comply with § 60.5380(a)(1), the records of closed vent system and cover inspections specified in paragraph (c)(6) of this section. (4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section. (i) The cumulative number of hours or operation or the number of months since initial startup, October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later. (ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period. (5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section. (i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390(c)(2). (ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required

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	and the reasons why. (iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period. (6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (iii) of this section. (i) An identification of each storage vessel with VOC emissions greater than 6 tpy constructed, modified or reconstructed during the reporting period. (ii) Documentation that the VOC emission rate is less than 6 tpy for meeting the requirements in § 60.5395(a). (iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period. (7)(i) Within 60 days after the date of completing each performance test as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. (ii) All reports required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in § 63.13 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (a)(2)(i) and (ii) of this section in paper format. **(3)**. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (10) of this section. All records must be maintained for at least 5 years. (1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i)

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	through (v) of this section. (i) Records identifying each well completion operation for each gas well affected facility; (ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375. (iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section. (A) For each gas well affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time. (B) For each gas well affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line. (iv) For each gas well facility for which you claim an exception under § 60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception. (v) For each gas well affected facility required to comply with both § 60.5375(a)(1) and (3), records of the digital photograph as specified in § 60.5410(a)(4). (4) For each gas well affected facility subject to both §60.5375(a)(1) and (3), you must maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.
Compliance enforcement / sanctions	Operators not in compliance of the Clean Air Act, NSPS OOOO are subject to civil and criminal penalties.

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What measures are shale gas extraction/production companies expected to implement to respond?	Gas venting from hydraulically fractured gas well completions is no longer allowed. Producers are expected to either install combustion devices such as flaring or use RECs when hydraulically fracturing new gas wells. As of 1 January 2015, all producers are expected to use RECs; with the exception of low pressure gas wells and exploration wells. Producers are also expected to install Vapor Recovery Units or some other cost-effective VOC mitigation technology on storage vessels that emit more than 6 tons of VOC per year. Furthermore; operators with centrifugal compressors with wet seals are expected to switch their wet seals with dry seals to achieve the 95% emission reductions. Finally, producers are expected to replace rod packing for reciprocating compressors at regular intervals.
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)	EPA estimates that combined annual costs of meeting the requirements would be $738,000,000 in 2015 with the value of the natural gas and condensate collected yielding an annual net savings of $45,000,000 as a result of those rules.[68] Specifically, the costs of compliance (without savings): $33,237 per completion.[69]
Emission reductions achieved (as a % of on-site fugitive methane emissions)	The average methane reduction per completion and recompletion is 201,000 m^3 (7,103 Mcf) (assuming average methane composition for gas well completions of 83%). [70] This translates to a 95% methane emission reduction.
Extent to which objectives met	It is too early to gauge the extent to which objectives have been met.

[68] http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20(01-08).pdf

[69] http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf, page 4-5

[70] http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf, page 5-2.

United States Federal Government – Greenhouse Gas Reporting Rule Subpart W

Aspect	Details
Name of policy / programme	Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas Systems
Responsible authority	U.S. Environmental Protection Agency
Date policy/ programme adopted	Latest revised version: 08/24/12 First year of reporting data: 2012
Objectives	The EPA's Greenhouse Reporting Program requires certain industries to report their greenhouse gas emissions. The goal is to better understand where greenhouse gas emissions are coming from. The ultimate goal is to use the emissions data to help inform policy, business, and regulator decisions. Subpart W of the Greenhouse Reporting Program governs Petroleum and Natural Gas Systems.[71] Owners or operators of facilities that contain petroleum and natural gas systems (onshore/offshore production, processing, transmission, underground storage, LNG equipment and storage, and distribution) and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalents) from process operations, stationary combustion, miscellaneous use of carbonates, and other source categories will report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule.
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	Natural gas production from shale gas wells in the U.S. has witnessed an exponential growth over the last 6 years. U.S. natural gas gross withdrawals from shale gas wells accounted for 30% of the total U.S. natural gas gross withdrawals in 2011, up from 8% in 2007.[72] The exponential increase in shale gas production has led to a rise in GHG emissions from the oil and natural gas sector. A rising source of GHG emissions is well completions from wells that use hydraulic fracturing. The shale gas boom has led to a dramatic increase in well completions that use hydraulically fracturing technology. During hydraulic fracturing, fracturing fluid (primarily water and proppant) is injected into the reservoir through the well tubing at high pressure. The fracturing fluid is then flowed back out the well, mixed with natural gas and condensate, which without a capture or combustion system is vented to the atmosphere. In an attempt to understand this new, potentially significant source of emissions, the EPA introduced in its new GHG reporting rule a provision that requires reporting emissions from well completions for hydraulically fractured gas wells.
Key drivers	Public health
Which on-site GHG fugitive emissions covered?	For an onshore petroleum and natural gas production facility, report CO_2, CH_4 , and N_2 O emissions from only the following source types on a single well-pad or

[71] Greenhouse Gas Reporting Program,

[72] Natural gas Gross Withdrawals and Production, EIA, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

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	associated with a single well-pad: 1. Natural gas pneumatic device venting. 2. Natural gas driven pneumatic pump venting. 3. Well venting for liquids unloading. 4. Gas well venting during well completions without hydraulic fracturing. 5. Gas well venting during well completions with hydraulic fracturing. 6. Gas well venting during well workovers without hydraulic fracturing. 7. Gas well venting during well workovers with hydraulic fracturing. 8. Flare stack emissions. 9. Storage tanks vented emissions from produced hydrocarbons. 10. Reciprocating compressor rod packing venting. 11. Well testing venting and flaring. 12. Associated gas venting and flaring from produced hydrocarbons. 13. Dehydrator vents. 14. EOR injection pump blowdown. 15. Acid gas removal vents. 16. EOR hydrocarbon liquids dissolved CO_2 . 17. Centrifugal compressor venting. 18. Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).
Details of requirements related to fugitive GHG minimisation	There are no requirements for fugitive GHG minimisation.
How were these requirements set? When reviewed and at what frequency?	The requirements for this rule were set by the EPA with consultation from oil and natural gas producing companies. The EPA will revise these rules as necessary.
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	The paragraphs shown below can be found under the "§ 98.234 Monitoring and QA/QC requirements" section of the rule: (a) You must use any of the methods described as follows to conduct leak detection(s) of equipment leaks and through-valve leakage from centrifugal compressors and reciprocating compressors: 1. *Optical gas imaging instrument.* 2. *Method 21.* 3. *Infrared laser beam illuminated instrument.* 4. *Acoustic leak detection device.* (b) To estimate the leak emissions, you must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure the leaked emissions. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard

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	practice. (c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled. (d) Use a high volume sampler to measure emissions within the capacity of the instrument. (f) Special reporting provisions: (1) Best available monitoring methods. EPA will allow owners or operators to use best available monitoring methods for parameters in § 98.233 Calculating GHG Emissions as specified in paragraphs (f)(2), (f)(3), and (f)(4) below. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section: (i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart. (ii) Supplier data. (iii) Engineering calculations. (iv) Other company records. (2) *Best available monitoring methods for well-related emissions.* During January 1, 2011 through December 31, 2011, owners and operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart. These well-related sources are: (i) Gas well venting during well completions and workovers with hydraulic fracturing as specified in § 98.233(g). (ii) Well testing venting and flaring as specified in § 98.233(l). (3) *Best available monitoring methods for specified activity data.* During January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart. These sources are: (i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (f), (g), (h), (l), (o), (p), (q), and (r). (ii) Number of blowdowns, completions, workovers, or other events in

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	§ 98.233(f), (g), (h), (i), and (w). (iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (k), (l), (m), (n), (x), (y), and (z). (4) *Best available monitoring methods for leak detection and measurement.* During January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for sources requiring leak detection and/or measurement that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part. These sources include: (i) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1). (ii) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2). (iii) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in § 98.232(c)(17) and (d)(6). (iv) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). (v) Condensate (oil and/or water) storage tanks in onshore natural gas transmission compression as specified in § 98.232(e)(3). Subpart W of 40 CFR part 98 includes provisions allowing owners and operators of facilities to use BAMM in lieu of specified data input requirements for determining GHG emissions in certain circumstances for specified emissions sources. However, some select sources may automatically use BAMM for calendar year 2011 without requesting approval from the Administrator.
Notification, reporting and verification	Annual reports are submitted to EPA electronically using an electronic greenhouse gas reporting tool (e-GGRT).

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requirements	EPA will verify the data submitted and will not require third party verification. Prior to EPA verification, reporters will be required to self-certify the data they submit to EPA. The paragraphs shown below can be found under the "§ 98.236 Data reporting requirements" section of the rule: **(1)** For natural gas pneumatic devices, report the following: (i) Actual count and estimated count separately of natural gas pneumatic high bleed devices as applicable. (ii) Actual count and estimated count separately of natural gas pneumatic low bleed devices as applicable. (iii) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices as applicable. (iv) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices. **(2)** For natural gas driven pneumatic pumps (refer to Equation W-2 of § 98.233), report the following, (i) Count of natural gas driven pneumatic pumps. (ii) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for all natural gas driven pneumatic pumps combined. **(3)** For dehydrators, report the following: (i) For each Glycol dehydrator with a throughput greater than or equal to 0.4 MMscfd, report the following (A) Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data. (B) Glycol dehydrator absorbent circulation pump type. (C) Whether stripper gas is used in glycol dehydrator. (D) Whether a flash tank separator is used in glycol dehydrator. (E) Type of absorbent. (F) Total time the glycol dehydrator is operating in hours. (G) Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.

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	(H) Concentration of CH_4 and CO_2 in wet natural gas. (I) What vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)). (J) For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2 e for each gas. (K) For each glycol dehydrator, report annual CO_2 , CH_4 , and N_2 O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons CO_2 e for each gas. (L) For the onshore natural gas processing industry segment only, report a unique name or ID number for glycol dehydrator. (ii) For all glycol dehydrators with a throughput less than 0.4 MMscfd, report the following: (A) Count of glycol dehydrators. (B) Which vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)). (C) Report annual CO_2 and CH_4 emissions at the facility level that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd. (D) Report annual CO_2, CH_4, and N_2O emissions at the facility level that resulted from the flaring of process gas, expressed in metric tons CO_2e for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd. (iii) For absorbent desiccant dehydrators, report the following: (A) Count of desiccant dehydrators. (B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2 e for each gas, for all absorbent desiccant dehydrators combined. (5) For well venting for liquids unloading, report the following: (i) For Calculation Methodology 1, report the following for each tubing diameter group and pressure group combination within each sub-basin category: (A) Count of wells vented to the atmosphere for liquids unloading. (B) Count of plunger lifts. Whether the selected well from the tubing

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	diameter and pressure group combination had a plunger lift (yes/no). (C) Cumulative number of unloadings vented to the atmosphere. (D) Average flow rate of the measured well venting in cubic feet per hour (refer to § 98.233(f)(1)(i)(A)). (E) Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet, selected to represent emissions in that tubing size and pressure combination. (F) Casing pressure, in psia, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift. (G) Tubing pressure, in psia, of each well selected to represent emissions in a tubing size group and pressure group combination that has a plunger lift. (H) Report annual CO_2 and CH_4 emissions, expressed in metric tons CO_2 e for each gas. (ii) For Calculation Methodologies 2 and 3 (refer to Equation W-8 and W-9 of § 98.233), report the following for each sub-basin category: (A) Count of wells vented to the atmosphere for liquids unloading. (B) Count of plunger lifts. (C) Cumulative number of unloadings vented to the atmosphere. (D) Average internal casing diameter, in inches, for all wells, where applicable. (E) Report annual CO_2 and CH_4 emissions, expressed in metric tons CO_2 e for each GHG gas. **(4)** For well completions and workovers, report the following for each sub-basin category: (i) For gas well completions and workovers with hydraulic fracturing by sub-basin and well type (horizontal or vertical) combination (refer to Equation W-10A and W-10B of § 98.233), report the following: (A) Total count of completions in calendar year. (B) When using Equation W-10A, measured flow rate of backflow during well completion in standard cubic feet per hour. (C) Total count of workovers in calendar year that flare gas or vent gas to

Aspect	Details
	the atmosphere. (D) When using Equation W-10A, measured flow rate of backflow during well workover in standard cubic feet per hour. (E) When using Equation W-10A, total number of days of backflow from all wells during completions. (F) When using Equation W-10A, total number of days of backflow from all wells during workovers. (G) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available. (H) Report number of workovers employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data. (I) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2 e for each gas. (J) Annual CO_2, CH_4, and N_2 O emissions that resulted from flares, expressed in metric tons CO_2 e for each gas. (ii) For gas well completions and workovers without hydraulic fracturing (refer to Equation W-13 of § 98.233): (A) Total count of completions in calendar year. (B) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere. (C) Total number of days of gas venting to the atmosphere during backflow for completion. (D) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2 e for each gas. (E) Annual CO_2 , CH_4 , and N_2 O emissions that resulted from flares, expressed in metric tons CO_2 e for each gas. **(5)** For gas emitted from produced oil sent to atmospheric tanks: (i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of § 98.233(j), report the following by sub-basin category, unless otherwise

Aspect	Details
	specified: (A) Number of wellhead separators sending oil to atmospheric tanks. (B) Estimated average separator temperature, in degrees Fahrenheit, and estimated average pressure, in psig. (C) Estimated average sales oil stabilized API gravity, in degrees. (D) Count of hydrocarbon tanks at well pads. (E) Best estimate of count of stock tanks not at well pads receiving your oil. (F) Total volume of oil from all wellhead separators sent to tank(s) in barrels per year. (G) Count of tanks with emissions control measures, either vapor recovery system or flaring, for tanks at well pads. (H) Best estimate of count of stock tanks assumed to have emissions control measures not at well pads, receiving your oil. (I) Range of concentrations of flash gas, CH_4 and CO_2. (J) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2 e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j). (K) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2 e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j). (L) Annual $CO_{2,}$ $CH_{4,}$ and N_2 O emissions that resulted from flaring gas, expressed in metric tons CO_2 e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Me In addition to the information required above, you must retain the following records: (a) Dates on which measurements were conducted. (b) Results of all emissions detected and measurements. (c) Calibration reports for detection and measurement instruments used. (d) Inputs and outputs of calculations or emissions computer model runs

Aspect	Details
	used for engineering estimation of emissions. (e) The records required under § 98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.
Compliance enforcement / sanctions	Emissions reports are verified through self-certification by the reporter and EPA verification. Each facility or supplier must have one and only one designated representative (DR) who certifies the report. Each facility can also have one alternate designated representative. While the designated representative does not need to be an employee at the reporting facility, the DR must be appointed by the owners and operators of the facility by a legally binding agreement. The data that are reported is used by EPA to verify the emissions, using a combination of electronic data quality assurance checks, and review of individual reports. The electronic reporting system has built-in range checks and completeness checks at the point of data entry by the reporter. EPA also conducts validation using algorithms and statistical analysis to identify potential errors and reviews individual reports. EPA intends to communicate with the reporter if it finds probable errors in reviewing the reports. If the report is determined to contain a "substantive error," the reporter would then follow the procedures in the rule to correct and resubmit the report. ***98.8 What are the compliance and enforcement provisions of this part?*** *Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414). A violation includes but is not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.* ***Enforcement (http://www.epa.gov/air/caa/peg/permits.html)*** *The Clean Air Act gives EPA enforcement powers over a range of civil and criminal sanctions. In general, when EPA finds that a violation has occurred, the agency can issue an order requiring the violator to comply, issue an administrative penalty order (use EPA administrative authority to force payment of a penalty), or bring a civil judicial action (sue the violator in court).*
What measures are shale gas extraction/production companies expected to implement to respond?	Shale gas extraction/production companies are expected to monitor and report their emissions so that they are in compliance with this rule.
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc.)	Not applicable as this is only a GHG reporting rule.
Emission reductions achieved (as a % of on-site fugitive methane	Not applicable as this is only a GHG reporting rule.

Aspect	Details
emissions)	
Extent to which objectives met	The first set of data was published in February of 2013. Producers utilized Best Available Monitoring Methods (BAMM) when reporting their data in 2012. As a result, the data does not accurately reflect actual emissions. It is expected that the accuracy of the data will improve in 2014 when producers are no longer allowed to use BAMM.

Wyoming Permitting Guidance

Aspect	Details
Name of policy / programme	Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance[73]
Responsible authority	State of Wyoming Department of Environmental Quality (DEQ)
Date policy/ programme adopted	Adopted June 1997, revised March 2010 (permitting guidance required for wells spud on or after August 1, 2010)
Objectives	Minimise air pollutants associated with oil and gas production facilities (such as VOCs, HAPs, nitrogen oxides, carbon monoxide, and hydrogen sulfide [methane only covered *indirectly* through these emissions reductions]. 3 specific areas are defined: 1. The Jonah-Pinedale Anticline Development (JPAD), 2. Concentrated Development Areas (CDAs) and 3. Statewide.
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	Public health focus to limit air pollutant emissions; reduction of ozone precursors is the primary driver of these efforts, as urban-level air pollution levels are seen in certain oil and gas production areas (mainly located in rural areas where such pollution levels are associated with O&G production)
Key drivers	Public health, reduction of ozone precursors
Which on-site GHG fugitive emissions covered?	VOCs, HAPs, nitrogen oxides, carbon monoxide, and hydrogen sulfide [methane only covered *indirectly* through these emissions reductions]
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	Direct requirements: Best Available Control Technology (BACT) applied (well site facilities only – not gas plants): <u>Flashing</u>: required for state-wide new facilities within 60 days of the first date of production, flashing emissions containing more than 10 TPY (tons per year) VOC must be controlled by at least 98% statewide; for JPAD region: 98% control of all new/modified tank emissions upon first date of production; CDAs must control 98% of all new/modified tank emissions of 8 TPY VOCs and above within 60 days of startup/ modification <u>Dehydration units</u>: *scenario 1 (applies to CDAs and statewide)* – all dehydration unit VOC and HAP emissions should be controlled at least 98% within 60 days of startup for VOC emissions at least 6 TPY or greater or 98% control within 30 days of startup for VOC emissions of 8 TPY and greater; after one year, combustion units used to meet 98% control can be removed if total potential VOC emissions are less than 6 TPY and all units are equipped with still vent condensers; *scenario 2 (applies to CDA and statewide)* – dehydration units equipped with glycol flash

[73] Wyoming permitting guidance: http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf

Aspect	Details
	separators and reboiler still vent condensers; removal of flash separators and condensers is not allowed; after 1 year, combustion units achieve 98% control may be removed if total potential VOC emissions from all units are less than 8 TPY and all units equipped with flash separators and still vent condensers; *additional JPAD measure*: 98% control of all new/modified dehydrator VOC/HAP emissions *at production start date.* Pneumatic pumps: VOC/HAP emissions associated with discharge stream of all gas-operated pneumatic pumps must be controlled at least 98% or routed to a closed loop system (e.g. sales line, collection line, fuel supply line). Pneumatic controllers: use of low-bleed (i.e., less than 6 cubic feet per hour, cfh) or no-bleed controllers or streams routed to a closed loop system Blow down/venting: during blow down/venting episodes (i.e., during liquids unloading, wellbore depressurization to prep for maintenance/repair, hydrate clearing, emergency operations, equipment depressurization, etc.), VOC/HAP emissions must be minimised, and personnel must remain onsite to make sure minimal venting occurs; specific recordkeeping and reporting requirements are established during the permitting process and include associated regulated air pollutants, reasons for episodes, duration, steps taken to minimise emissions, and description of emission estimation methods Minor source permitting: For emission sources (other than tanks, dehydrators, pneumatic controllers/pumps, and water tanks) without presumptive BACT requirements, uncontrolled sources emitting greater than 8 TPY VOC or 5 TPY total HAPs that do not have P-BACT requirements, a BACT analysis must be filed with the permit application Leak detection and repair program: adoption of NSPS Subpart KKK regulations.
How were these requirements set? When reviewed and at what frequency?	Permit guidance document
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	Emissions calculations defined by BACT cost analysis worksheet and other permit applications forms
Notification, reporting and verification requirements	Permitting guidance
Compliance enforcement / sanctions	Failure to comply with Wyoming air quality regulations may result in enforcement of the "Notice of Violation and penalties up to $10,000/day.
Other environmental control provisions	Wyoming Air Quality Standards and Regulations (WAQSR): http://deq.state.wy.us/aqd/standards.asp US EPA State Implementation Plan (SIP): https://yosemite.epa.gov/R8/R8Sips.nsf/Wyoming?OpenView&ExpandView
Links to other policies	See above.
What measures are shale gas extraction/production companies expected to implement to respond?	Install BACT equipment as specified in the permitting guidance.

Aspect	Details
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)[74]	N/A
Emission reductions achieved (as a % of on-site fugitive methane emissions)[75]	N/A
Extent to which objectives met	
Cost/well (€)	See above.
Share of Drilling Costs (%)	See above.

Wyoming Green Completions Guidance Permit

Aspect	Details
Name of policy / programme	Green completions (Form ADQ-OG11)[76]
Responsible authority	State of Wyoming Department of Environmental Quality – Air Quality Division
Date policy/ programme adopted	2010[77]
Objectives	Minimise VOC and HAP emissions [GHGs only covered *indirectly* through VOC emissions reductions] associated with flaring/venting to the extent possible by routing liquids to storage tanks and gas into gas sales line or collection system in the Jonah and Pinedale Anticline Development Area (JPAD) and the Concentrated Development Area (CDA), which includes Sublette, Lincoln, Uinta, Carbon, Sweetwater, Freemont, and Natrona counties.
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security,	Minimise air pollutants associated with oil and gas production facilities (such as VOCs, HAPs, nitrogen oxides, carbon monoxide, and hydrogen sulfide [methane only covered *indirectly* through these emissions reductions]. Emissions reductions focused on the Jonah and Pinedale Anticline Development Area (JPAD) and the Concentrated Development Area (CDA), which includes Sublette, Lincoln, Uinta, Carbon, Sweetwater, Freemont, and Natrona counties

[74] $5-$10 million per well assumed for horizontal well drilling costs. Source: Lipschultz, Marc. "Historic Opportunities from the Shale Gas Revolution." KKR, November 2012: New York, NY.

[75] ICF estimates GHG emissions from top sources during shale gas well production at 16.5 million cubic feet. Top sources of emissions on hydraulically fractured shale gas wells include (from largest share of emissions to smallest): venting during completion, venting during recompletion, equipment leaks, venting during liquids unloading, pneumatic device venting, dehydrator venting, reciprocating compressor rod packing venting, and storage tank venting.

[76] Wyoming permit: http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf

[77] Wyoming conference report, p. 14. http://www.uwyo.edu/ser/_files/docs/conferences/hydraulic-fracturing/hydraulic-fracturing-summary-report.pdf

Aspect	Details
environmental)	
Key drivers	Public health and ozone precursors
Which on-site GHG fugitive emissions covered?	VOCs [GHGs only covered *indirectly* through VOC emissions reductions]
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	Direct requirement: capture (rather than flare or vent) emissions at the well site during completions and recompletion activities. Exceptions to REC requirements must be requested in permit application (flaring would be used instead). "The opacity of visible emissions associated with the flaring of hydrocarbon fluids associated with completion and re-completion activities shall be limited to twenty percent (20%) as determined by 40 CFR Part 60, Appendix A, Method 9."[78]
How were these requirements set? When reviewed and at what frequency?	Requirements set out as Wyoming Air Quality Standards and Regulations, Chapter 6, Section 2 permit application to conduct well completion and re-completion activities per the Chapter 6, Section 2 Oil and Gas Production Facilities Permitting Guidance, revised March 2010. Completion/recompletion emissions associated with flaring/venting are to be eliminated "to the extent practicable."[79] The Air Quality Division will revise this permit as necessary.
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	Total volumes of hydrocarbon liquids (bbl) and natural gas (m^3) recovered (flared, vented, stored in tanks, pits, trucks, or other containment, or sold) from the wellbore during completion/recompletion, as well as percentage of total hydrocarbon liquids/gases recovered that were flared/vented and well completions emissions worksheet. Total tons of VOCs, HAPs, nitrogen oxides (NO_x), and carbon monoxide (CO) emissions associated with flaring/venting captured for each completion/recompletion on a per-well basis. Records must be kept for 5 years. The division must be notified of each well completion/recompletion at least 15 days prior to start of activity, and submit summary of recovered gas/hydrocarbons/emissions within 90 days of first date of production.
Notification, reporting and verification requirements	Completion of Well Completions Emissions Worksheet for CDA or JPAD region
Compliance enforcement / sanctions	Enforceable as conditions of well completion permit[80]
Other environmental control provisions	Form AQD-OG3 (storage tanks, pressurized vessels, and pneumatic pumps), form AQD-OG4 (Dehydration units), Form AQD-OG12 (Blowdown/venting permit application), Installation of equipment air permit requirements, reporting guidelines for well flaring/venting)[81]
Links to other policies	http://deq.state.wy.us/aqd/oilgas.asp
What measures are shale	Install REC equipment to capture flared/vented emissions at wellbore. Notify Air

[78] Wyoming REC permit: p. 2

[79] Wyoming REC permit: p. 2

[80] Wyoming regulation: http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf

[81] Wyoming list of O&G regulations: http://deq.state.wy.us/aqd/oilgas.asp

Aspect	Details
gas extraction/production companies expected to implement to respond?	Quality Division of each well completion/recompletion at least 15 days in advance of activity; within 90 days of first day of production for newly completed/recompleted well, submit a summary of hydrocarbon volumes captured Eliminate VOC and HAP emissions [GHGs only covered *indirectly* through VOC emissions reductions] associated with flaring/venting to the extent possible by routing liquids to storage tanks and gas into gas sales line or collection system. Green completion permit required for all well completions/recompletions after issuance of permit (2010).
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)[82]	BP in 2002-2005 (estimate for 25-well annual REC program) – CAPEX: $500,000, setup costs: $15,000/yr, labour costs: $106,250/yr, natural gas volume savings: 7.65 million m^3/yr (270,000 Mcf/yr), gas savings value: $1.9 million/yr, additional savings: $175,000/yr, or net value of gas savings of $20,000/well[83]
Emission reductions achieved (as a % of on-site fugitive methane emissions)[84]	BP in 2002-2005 (Green River Basin) – average of 93.4 TCM (3,300 Mcf) of natural gas sold rather than vented per well (or 20% of GHG emissions/well) and total of 6,700 bbl of condensate total on 106 wells, or net value of $20,000/well[85] WY/CO/UT: Anadarko (tight formations) – 2006-2008 613 wells/yr used RECs, resulting in a net savings of 58.1 million m^3 per year (2,052 MMcf/yr) (average of 93.4TCM/well (3.3 MMcf/well), or 20% of GHG emissions/well, despite 45% increase in well completions, and $10.3 million/yr in increased revenues[86] ICF: 204.7 TCM/completion (7,230 Mcf/) (completion in methane emissions captured during completion/recompletion (or 44% of GHG emissions/well)
Extent to which objectives met	
Cost/well (€)	See above.
Share of Drilling Costs (%)	See above.

[82] $5-$10 million per well assumed for horizontal well drilling costs. Source: Lipschultz, Marc. "Historic Opportunities from the Shale Gas Revolution." KKR, November 2012: New York, NY.

[83] EPA GasSTAR, p. 9. http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf

[84] ICF estimates GHG emissions from top sources during shale gas well production at 16.5 million cubic feet. Top sources of emissions on hydraulically fractured shale gas wells include (from largest share of emissions to smallest): venting during completion, venting during recompletion, equipment leaks, venting during liquids unloading, pneumatic device venting, dehydrator venting, reciprocating compressor rod packing venting, and storage tank venting.

[85] EPA GasSTAR, 10. http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf

[86] P. 12. http://www.globalmethane.org/documents/events_oilgas_20090127_techtrans_day2_robinson1_en.pdf

Colorado Oil and Gas Conservation Commission (COGCC) Guidance

Aspect	Details
Name of policy / programme	COGCC HB-07-1341, Section 805.b[87]: Section 2a: Storage tanks Section 2c: Dehydrators Section 2e: Pneumatic controllers Section 3: Green completions
Responsible authority	Colorado Oil and Gas Conservation Commission (COGCC)
Date policy/ programme adopted	2009
Objectives	Minimise release of GHGs such as methane and maximize recovery of the natural resource by diverting gas to the sales line, rather than the atmosphere when technically/economically feasible[88]
Context	Population density (in some cases) and public health issues due to the cumulative air quality issues; pollution in and around production areas is on par with urban levels, in some cases, and directly attributable to the oil and gas industry; green completions attempts to minimise this
Key drivers	Ozone-related public health
Which on-site GHG fugitive emissions covered?	Green completions reduce methane emissions indirectly, while other measures also indirectly reduce methane, nitrous oxide and carbon dioxide.
Details of requirements related to fugitive GHG minimisation **(direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)**	Storage tanks: 95% VOC reduction for liquids storage tanks if uncontrolled emissions are 5 tons per year (TPY) or more within a quarter mile of an affected area (applies only to Garfield, Mesa, and Rio Blanco counties) Dehydrators: 90% reduction in VOCs required where uncontrolled VOC emissions are at least 5 TPY within a quarter mile of an affected building (applies only to Garfield, Mesa, and Rio Blanco counties) Pneumatic controllers: No- or low-bleed requirements for new, repaired, or replaced devices where feasible Green completions: "Green completion practices are required on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of 14 TCM per day (500 MCFD) to the surface against an induced surface backpressure of five hundred 34.5 bar (500 psig) or sales line pressure, whichever is greater. Green

[87] Colorado list of regulations: http://www.oilandgasbmps.org/laws/colorado_law.php
[88] Colorado regulation presentation: http://cogcc.state.co.us/rulemaking/HearingDocuments/Green%20Completion%20Presentation.pdf

Aspect	Details
	completion practices are not required for exploratory wells, where the wells are not sufficiently proximate to sales lines, or where green completion practices are otherwise not technically and economically feasible..."[89] Practices include: "i. The operator shall employ sand traps, surge vessels, separators, and tanks as soon as practicable during flowback and cleanout operations to safely maximize resource recovery and minimise releases to the environment. ii. Well effluent during flowback and cleanout operations prior to encountering hydrocarbon gas of salable quality or significant volumes of condensate may be directed to tanks or pits (where permitted) such that oil or condensate volumes shall not be allowed to accumulate in excess of twenty (20) barrels and must be removed within twenty-four (24) hours. The gaseous phase of non-flammable effluent may be directed to a flare pit or vented from tanks for safety purposes until flammable gas is encountered. iii. Well effluent containing more than ten (10) barrels per day of condensate or within two (2) hours after first encountering hydrocarbon gas of salable quality shall be directed to a combination of sand traps, separators, surge vessels, and tanks or other equipment as needed to ensure safe separation of sand, hydrocarbon liquids, water, and gas and to ensure salable products are efficiently recovered for sale or conserved and that non-salable products are disposed of in a safe and environmentally responsible manner. iv. If it is safe and technically feasible, closed-top tanks shall utilize backpressure systems that exert a minimum of four (4) ounces of backpressure and a maximum that does not exceed the pressure rating of the tank to facilitate gathering and combustion of tank vapors. Vent/backpressure values, the combustor, lines to the combustor, and knock-outs shall be sized and maintained so as to safely accommodate any surges the system may encounter. v. All salable quality gas shall be directed to the sales line as soon as practicable or shut in and conserved. Temporary flaring or venting shall be permitted as a safety measure during upset conditions and in accordance with all other applicable laws, rules, and regulations." Where green completions are not technically feasible or required, operators should employ Best Management Practices to reduce emissions, including minimizing the time period during which gases are emitted to the atmosphere, monitoring or recording the volume and time period of such emission's.

[89] Colorado regulation presentation: http://cogcc.state.co.us/rulemaking/HearingDocuments/Green%20Completion%20Presentation.pdf

Aspect	Details
How were these requirements set? When reviewed and at what frequency?	Requirements set by Colorado Oil and Gas Conservation Commission regulation (Rule 805.b)
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	Conditions of permitting
Notification, reporting and verification requirements	Conditions of permitting
Compliance enforcement / sanctions	Enforceable as conditions of permitting
Other environmental control provisions	EPA State Implementation Plan (SIP): https://yosemite.epa.gov/R8/R8Sips.nsf/Colorado?OpenView Colorado Oil and Gas Emissions Rule: http://lewisvilletexan.com/xoops/uploads/47615076-763a-a964.pdf
Links to other policies	See above.
What measures are shale gas extraction/production companies expected to implement to respond?	Install equipment to capture flared/vented emissions at wellbore and specified production areas.
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)[90]	N/A

[90] $5-$10 million per well assumed for horizontal well drilling costs. Source: Lipschultz, Marc. "Historic Opportunities from the Shale Gas Revolution." KKR, November 2012: New York, NY.

Aspect	Details
Emission reductions achieved (as a % of on-site fugitive methane emissions[91])	RECs: WY/CO/UT: Anadarko (tight formations) – 2006-2008 613 wells/yr used RECs, resulting in a net savings of 58 million m^3per year (average of 93.4 TCM/well, or 20% of GHG emissions/well, despite 45% increase in well completions, and $10.3 million/yr in increased revenupes[92] FW: Devon (Fort Worth Basin) sold an average of 337 TCM/well (72% of GHG emissions/well) of natural gas (rather than venting) on 30 wells, or a net value of $59,500/well at $5/Mcf; expecting emissions reductions of 42.4-56.6 million m^3yr in the future[93] ICF: 204.7 TCM/completion (7,230 Mcf/completion) in methane emissions captured during completion/recompletion (or 44% of GHG emissions/well)
Extent to which objectives met	
Cost/well (€)	See above.
Share of Drilling Costs (%)	See above.

[91] ICF estimates GHG emissions from top sources during shale gas well production at 16.5 million cubic feet. Top sources of emissions on hydraulically fractured shale gas wells include (from largest share of emissions to smallest): venting during completion, venting during recompletion, equipment leaks, venting during liquids unloading, pneumatic device venting, dehydrator venting, reciprocating compressor rod packing venting, and storage tank venting.

[92] P. 12. http://www.globalmethane.org/documents/events_oilgas_20090127_techtrans_day2_robinson1_en.pdf

[93] Global Methane, p. 13. http://www.globalmethane.org/documents/events_oilgas_20090127_techtrans_day2_robinson1_en.pdf

Colorado Department of Public Health and Environment (CDPHE) Air Quality Control Commissions Regulations

Aspect	Details
Name of policy / programme	CDPHE Regulation 7 – Emissions of Volatile Organic Compounds, Section XII CDPHE Regulation 3 – Minor source permitting[94]
Responsible authority	Colorado Department of Public Health and Environment (CDPHE)
Date policy/ programme adopted	2009
Objectives	Minimise release of GHGs such as methane indirectly and maximize recovery of the natural resource by diverting gas to the sales line, rather than the atmosphere when technically/economically feasible[95]
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	Population density (in some cases) and public health issues due to the cumulative air quality issues; pollution in and around production areas is on par with urban levels, in some cases, and directly attributable to the oil and gas industry; green completions attempts to minimise this
Key drivers	Ozone-related public health issues
Which on-site GHG fugitive emissions covered?	Green completions reduce methane emissions indirectly, while other measures also indirectly reduce methane and other GHG emissions such as nitrous oxide and carbon dioxide
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	Regulation 7: Pneumatic controllers: No- or low-bleed pneumatic devices for all new and existing applications in non-attainment areas (though exceptions are allowed) Storage tanks: 95% VOC reduction at gas processing plants in non-attainment areas if uncontrolled emissions from condensate tanks reach at least 2 tons per year (TPY); 95% VOC reduction in condensate storage tanks if uncontrolled emissions reaches at least 20 TPY; for condensate storage tanks with past uncontrolled emissions of less than 20 TPY VOC emissions, may be subject to 95% VOC reduction for newly drilled wells or recompletions/stimulations (operators are given 90 days after 1st date of production to install control equipment, though if emissions are below 20 TPY, operator is required to notify the Department with an explanation of methodology; condensate tanks in ozone non-attainment areas must be controlled under a system-wide approach Dehydrators: 90% reduction in VOCs where uncontrolled VOC emissions are 15 TPY or greater Leak detection and repair in gas processing: Colorado adopted NSPS Subpart

[94] http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20(01-08).pdf, p. 22.

[95] Colorado regulation presentation: http://cogcc.state.co.us/rulemaking/HearingDocuments/Green%20Completion%20Presentation.pdf

Aspect	Details
	KKK (adopted for processing plants in non-attainment areas regardless of date of construction) Regulation 3: Minor source permitting is required for sources with thresholds varied (generally criteria emissions exceeding 1-5 TPY in non-attainment areas, or statewide for 5-10 TPY threshold, depending on the pollutant
How were these requirements set? When reviewed and at what frequency?	Requirements set by Colorado Department of Public Health and Environment, regulations 3 and 7
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	Conditions of permit
Notification, reporting and verification requirements	Conditions of permit
Compliance enforcement / sanctions	Enforceable as conditions of permitting
Other environmental control provisions	EPA State Implementation Plan (SIP): https://yosemite.epa.gov/R8/R8Sips.nsf/Colorado?OpenView Colorado Oil and Gas Emissions Rule: http://lewisvilletexan.com/xoops/uploads/47615076-763a-a964.pdf
Links to other policies	See above.
What measures are shale gas extraction/production companies expected to implement to respond?	Install equipment to capture flared/vented emissions during completion and production
Data on costs of expected mitigation	N/A

Aspect	Details
measures (per well, as a % of drilling costs, etc)[96]	
Emission reductions achieved (as a % of on-site fugitive methane emissions[97])	N/A
Extent to which objectives met	
Cost/well (€)	See above.
Share of Drilling Costs (%)	See above.

[96] $5-$10 million per well assumed for horizontal well drilling costs. Source: Lipschultz, Marc. "Historic Opportunities from the Shale Gas Revolution." KKR, November 2012: New York, NY.

[97] ICF estimates GHG emissions from top sources during shale gas well production at 16.5 million cubic feet. Top sources of emissions on hydraulically fractured shale gas wells include (from largest share of emissions to smallest): venting during completion, venting during recompletion, equipment leaks, venting during liquids unloading, pneumatic device venting, dehydrator venting, reciprocating compressor rod packing venting, and storage tank venting.

Fort Worth, TX Gas Drilling and Production Ordinance

Aspect	Details
Name of policy / programme	Gas Drilling and Production[98] (Ordinance No.: 18449-02-2009)[99]
Responsible authority	City of Fort Worth Gas Inspector
Date policy/ programme adopted	2009
Objectives	Minimise the release of natural gas and vapours to the environment during completion/recompletion in the Barnett Shale
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	Population density and public health issues – limit emissions' impact on nearby communities in Fort Worth, TX
Key drivers	Public health
Which on-site GHG fugitive emissions covered?	Natural gas [methane]
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	The ordinance provides a number of direct "On site and technical regulations" to reduce GHG emissions, including: #16e: Fracturing Operations – "At no time shall the well be allowed to flow or vent directly to the atmosphere without first directing the flow through separation equipment or into a portable tank."[100] #28: Reduced Emission Completion – All wells that have a sales line are required to use REC techniques. RECs not required for wells that do not have a sales line and were permitted before July 1, 2009 or Is the first permitted well on a pad site REC exemptions requested from Gas Inspector if RECs are deemed infeasible or would endanger personnel/public (flaring would be used instead – flaring not allowed within 300 feet of any building not used in operations on drilling site and must be screened)[i]. #36: Vapour Recovery for Storage Tanks – "Vapor recovery equipment shall be required for tank batteries that have an estimated rolling annual aggregate emissions rate of 25 tons or greater of total volatile organic hydrocarbons per year per well head. Vapor recovery equipment must be operated and maintained in such a way to ensure a 95% recovery efficiency between the internal and external atmospheres of the tank(s)."[101]

[98] All gas wells in the Fort Worth, TX area are shale gas wells; thus, this ordinance applies to all shale gas production.

[99] Fort Worth Ordinance, p. 8, CCC. http://fortworthtexas.gov/uploadedFiles/Gas_Wells/090120_gas_drilling_final.pdf

[100] Fort Worth Ordinance, p. 34.

[101] Fort Worth Ordinance, p. 40.

Aspect	Details
How were these requirements set? When reviewed and at what frequency?	City of Forth Worth sets requirements and makes changes where necessary
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	The City Manager designates a Gas Inspector, who enforces the Ordinance provisions, and has the authority to enter/inspect any premises covered by the provisions of the ordinance at any time.[102]
Notification, reporting and verification requirements	A gas well permit is required for drilling, redrilling, deepening, reentering, activating, or converting each well (and a new gas well permit is also required for reentering or drilling an abandoned well). In addition, reworking a permitted well or to fracture stimulate a permitted well after initial completion or to conduct seismic surveys or exploratory activities requires written notice to the Gas Inspector and posting a sign at the site at least 10 days before commencing.[103]
Compliance enforcement / sanctions	Enforceable as conditions of well completion permitting.
Other environmental control provisions	Air quality study on ambient air monitoring, point source testing, air dispersion modelling, and public health evaluation; study found no evidence of gas exploration-related pollutants reaching concentrations above applicable screening levels (highest recorded concentrations were lower than the Texas Commission on Environmental Quality, TCEQ, levels); however, dispersion modelling analysis indicates that benzene emissions from storage tanks could reach pollution levels slightly higher than TCEQ's short-term screening levels, and found that sites containing multiple large-line engines could emit acrolein and formaldehyde at offsite ambient air concentrations exceeding TCEQ's short- and long-term screening levels EPA State Implementation Plan (SIP) Texas Commission on Environmental Quality (TCEQ) well completion/flowback notification forms North Central Texas Council of Governments emissions inventory for on-road mobile sources in the Barnett Shale to assist in refining emissions inventories for the SIP
Links to other policies	Air quality studies: http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf, http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/DOE-NETL-2011-1478%20Marcellus-Barnett.pdf EPA State Implementation Plan: http://www.tceq.texas.gov/agency/air_main.html#sip TCEQ completion/flowback notification forms: http://www.tceq.texas.gov/assets/public/permitting/air/Forms/20640.pdf North Central Texas Council emissions inventory study:

[102] Fort Worth Ordinance, pp. 9-10.

[103] Fort Worth Ordinance, pp. 10-11.

Aspect	Details
	http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/mob/5821113174FY1101-20120831-NCTCOG-BarnettShale_oil_gas_mobile_ei.pdf
What measures are shale gas extraction/production companies expected to implement to respond?	Install equipment to capture flared/vented emissions at wellbore to minimise the release of natural gas and vapours to the environment during completion/recompletion and fracturing through application of equipment to minimise emissions
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)[104]	RECs: 1: Partner Company A (Fort Worth Basin) - $8,700/well in incremental cost, or 0.1%-0.2% of current horizontal per-well drilling costs[105] 2: Devon (Fort Worth Basin) performed RECs on 30 wells; cost/well: $8,700, or 0.1%-0.2% of current horizontal per-well drilling costs[106]
Emission reductions achieved (as a % of on-site fugitive methane emissions[107])	RECs: Devon (Fort Worth Basin) sold an average of 337 TCM/well (11,900Mcf/well) (72% of GHG emissions/well) of natural gas (rather than venting) on 30 wells, or a net value of $59,500/well at $5/Mcf; expecting emissions reductions of 42.4-56.6 million m^3 per year (1.5-2.0 Bcf per year) in the future[108] ICF: 204.7 TCM/completion (7,230 Mcf/completion) in methane emissions captured during completion/recompletion (or 44% of GHG emissions/well)
Extent to which objectives met	
Cost/well (€)	See above.
Share of Drilling Costs (%)	See above.

[104] $5-$10 million per well assumed for horizontal well drilling costs. Source: Lipschultz, Marc. "Historic Opportunities from the Shale Gas Revolution." KKR, November 2012: New York, NY.

[105] EPA GasSTAR, p. 10.

[106] Global Methane, p. 13. http://www.globalmethane.org/documents/events_oilgas_20090127_techtrans_day2_robinson1_en.pdf

[107] ICF estimates GHG emissions from top sources during shale gas well production at 16.5 million cubic feet. Top sources of emissions on hydraulically fractured shale gas wells include (from largest share of emissions to smallest): venting during completion, venting during recompletion, equipment leaks, venting during liquids unloading, pneumatic device venting, dehydrator venting, reciprocating compressor rod packing venting, and storage tank venting.

[108] Global Methane, p. 13. http://www.globalmethane.org/documents/events_oilgas_20090127_techtrans_day2_robinson1_en.pdf

Draft Ozone Action Plan in Utah, USA

Aspect	Details
Name of policy / programme	Ozone Action Plan (OAP)
Responsible authority	Bureau of Land Management (BLM) and Utah Department of Environmental Quality – Division of Air Quality
Date policy/ programme adopted	OAP is still draft; likely to come into play in 2014. The Final Environmental Impact Statement (FEIS) was submitted March 2012[109] and the Record of Decision (ROD) was approved in May 2012[110].
Objectives	Primarily to reduce emissions of NO_x and VOCs to avoid ozone formation. However, the same measures will also be effective at reducing emissions of methane, and other criteria pollutants such as carbon monoxide and sulphur dioxide and toxic air pollutants such as benzene.
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	The Greater Natural Buttes Project Area (GNBPA) encompasses approximately 162,911 acres in an existing gas producing area in Uintah County in the state of Utah. The GNBPA lands are owned by the federal government, the State of Utah, the Ute tribe and other private land owners. O&G activities are very important economically for rural populations. Kerr-McGee Oil & Gas Onshore LP (KMG), a wholly owned subsidiary of Anadarko Petroleum Corporation, is developing the oil and gas resources within GNBPA. It currently includes 1,562 oil and gas wells and associated infrastructure (including 23 compressor stations, access roads, water management facilities, pipelines and power lines). The gas field is a conventional gas resource in which the majority of the wells are hydraulically fractured to facilitate production. It is relevant as the methane emissions are significant for regional photochemical smogs/ozone as well as being an issue for global warming. In 2006, KMG proposed a significant increase in well drilling and development activities in the GNBPA beyond what is currently permitted. Under the proposal, up to 3,675 new natural gas wells would be drilled from 1,484 well pads over a period of 10 years. Under the proposed expansion, KMG intends to develop all potentially productive subsurface formations underlying the GNBPA. The formations include, but are not limited to, the Green River Formation, Wasatch Formation, Mesa Verde Group (including the Blackhawk Formation), Mancos Shale, and Dakota Sandstone. As much of the GNBPA is located on federal land under the jurisdiction of the BLN, pursuant to the National Environmental Policy Act (NEPA), an Environmental Impact Statement (EIS) was prepared to address potential impacts from the implementation of the project. The OAP was built into the EIS

[109] http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_.html

[110] http://www.blm.gov/pgdata/etc/medialib/blm/ut/vernal_fo/planning/greater_natural_buttes/record_of_decision.Par.86388.File.dat/Cover_ROD.pdf

Aspect	Details
	to address ozone concerns (see below)
Key drivers	Monitoring of winter ozone levels in the Uinta Basin during 2010 and 2011 revealed concentrations at levels above the US EPA National Ambient Air Quality Standards (NAAQS), prompting the BLM to consider additional mitigation measures in the EIS.
Which on-site GHG fugitive emissions covered?	The Ozone Action Plan focusses on criteria pollutants (CO, NO_x, PM, SO_x). However, the proposed measures (see below) have impacts on GHG fugitive emissions including CO_2 and CH_4.

Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	The following specific control and monitoring measures are included in the Ozone Action Plan (considered as BACT):
	• Low emission glycol dehydrators at all existing and new compressor stations and production wells.
	• Electric compression, where feasible (approximately 50% of the compression hp to be electrically driven).
	• Emission controls having a control efficiency of 95% on existing condensate tanks with a potential to emit of greater 20 TPY, and on new condensate tanks with a potential to emit of 5 TPY VOCs.
	• Low-bleed pneumatic devices would be installed at all new compressor stations and production facilities. Within 6 months after of the ROD, all existing high-bleed pneumatic devices would be replaced with low bleed pneumatic devices. High-bleed devices may be allowed to remain in service for critical safety and/or process reasons.
	• Green completions for all well completion activities.
	• Tier II drill rig engines by 2012, with phase-in of Tier IV engines or equivalent emission reduction technology as soon as possible thereafter, but no later than 2018.
	• A natural gas or liquid natural gas drilling rig engine pilot project would be implemented as soon as operationally feasible, but no later than 1 year after the ROD. This pilot project would ascertain emission reduction benefits, operating experience and, if successful, may result in more natural gas or liquid natural gas engine use in the Uinta Basin.
	• Lean burn natural gas-fired stationary compressor engines or equipment with equivalent emission rates.
	• Catalyst on all natural gas-fired compressor engines to reduce the emissions of CO and VOCs.
	• Dry seals on new centrifugal compressors.
	• An annual inspection and maintenance program to reduce VOC emissions, including:
	  ○ Performing inspections of thief hatch seals and Enardo pressure relief valves to ensure proper operations.
	  ○ Reviewing gathering system pressures to evaluate any areas where gathering pressure may be reduced, resulting in lower flash losses from the condensate storage tanks
	
	Additional control and monitoring would be triggered under certain circumstances, including a re-designation of the area as “nonattainment” for ozone by the US EPA. The additional requirements would be (considered to

Aspect	Details
	be MACT): • Reducing the total number of drill rigs. • Installing Tier IV or better drill rig engines. • Seasonally reducing or ceasing drilling during specified periods. • Using only lower-emitting drill and completion rig engines during specified time periods. • Using natural gas-fired drill and completion rig engines. • Replacing internal combustion engines with gas turbines for natural gas compression. • Using electric drill rig or compression engines. • Centralizing gathering facilities. • Limiting blowdowns or restricting them during specified periods. • Installing plunger lift systems with smart automation. • Employing a monthly Forward Looking Infrared, or FLIR, program to reduce VOCs. • Enhancing a direct inspection and maintenance program. • Employing tank load out vapor recovery. • Employing enhanced VOC emission controls with 95% control efficiency on additional production equipment having a potential to emit of greater than 5 tpy.
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	Conditions of permitting.
Notification, reporting and verification requirements	Conditions of permitting
Compliance enforcement / sanctions	Enforceable as conditions of permitting
Other environmental control provisions	See above
Links to other policies	The CAA of 1970 (42 USC 7401 et seq.) as amended in 1977 and 1990 is the basic federal statute governing air pollution. Provisions of the CAA of 1970 that potentially are relevant to the GNBPA are listed below: • NAAQS; • Prevention of Significant Deterioration (PSD); • Nonattainment New Source Review (NNSR); • Conformity Regulations; • New Source Performance Standards (NSPS); and • Maximum Achievable Control Technology (MACT) Standards.

Aspect	Details
What measures are shale gas extraction/production companies expected to implement to respond?	See above
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc)	No data available
Emission reductions achieved (as a % of on-site fugitive methane emissions)	Implementation of these additional mitigation measures is intended to address adverse ozone impacts but also may lead to changes in GHG emissions. Some of the measures may reduce GHG emissions (e.g. the use of low-emission dehydrators, low-bleed pneumatics, and green completion techniques to control emissions of CH_4), while others may increase GHG emissions (e.g. the use of electric compression and lean-burn natural gas-fired engines). The net effect of the mitigation measures (where quantifiable) would be a 4% increase in GHG emissions (as CO_2e). This primarily is due to the use of electric compression, which uses mostly coal-fired sources of electricity, and the increased emission of CH_4 and N_2O from leanburn natural gas-fired engines. The implementation of these additional mitigation measures represents a trade-off of air quality improvements in the GNBPA for an increase in GHG emissions locally and at distant coal-fired power plants.
Extent to which objectives met	Plan is still in draft format.

New York State GHG Emissions Impacts Mitigation Draft Plan

Aspect	Details
Name of policy / programme	GHG Emissions Impacts Mitigation Plan *draft*[111,112]
Responsible authority	New York State Department of Environmental Conservation (DEC)
Date policy/ programme adopted	Draft only (as of February 2013)
Objectives	To mitigate GHG emissions from shale gas production, particularly methane, given its global warming potential. "The Department proposes to require, as a permit condition for high-volume hydraulic fracturing that the operator construct and operate the site in accordance with a greenhouse gas emissions impacts mitigation plan that may incorporate the above practices [participation in the EPA's Gas STAR program, leak detection/repair, and effective planning/implementation of necessary activities] and considers, to the extent practicable, any applicable Department policy documents."[113]
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security, environmental)	The Supplemental Generic Environmental Impact Statement (SGEIS) is meant to provide shale-related production activities, such as hydraulic fracturing, in the event that the moratorium is lifted. These draft regulations go beyond established conventional oil and gas regulations.
Key drivers	Public health and environmental concerns
Which on-site GHG fugitive emissions covered?	Nitrogen oxides, methane[114]
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health	"At a minimum the plan would include[115]: • A list of GHG-related Best Management Practices (BMPs) planned for implementation at the permitted well site (see later section); • A Leak Detection and Repair Program consistent with the SGEIS (permit program) (see later section); • Required use and a description of EPA's Natural Gas STAR Best Management Practices [and proof of participation in Natural Gas STAR

[111] New York currently has a moratorium on hydraulic fracturing due to public safety concerns. The New York State Department of Environmental Conservation (DEC) released a Supplemental Generic Environmental Impact Statement (SGEIS) that details regulatory provisions focused on shale-related production activities, such as hydraulic fracturing, in the event that the moratorium is lifted. The most recent version (2011) of the *draft* regulations is available at http://www.dec.ny.gov/data/dmn/rdsgeisfull0911.pdf.

[112] NYS SGEIS draft, chapter 7, section 7.6, p.7-116. http://www.dec.ny.gov/energy/75370.html

[113] NYS SGEIS, p.7-117.

[114] SGEIS, Appendix 25.

[115] SGEIS, pp. 7-116-7-117.

Aspect	Details
impacts or resource conservation)	program] for any equipment (e.g., low bleed gas-driven pneumatic valves and pumps) located from the wellhead to the onsite separator's outlet • A description of planned use of reduced emissions completions [RECs regulation], if any, including an estimate of the amount of methane that would be recovered instead of flared by the use of such and a permit program on RECs to be performed whenever a sales line is available during completion [see table on RECs regulation for more details] • A statement that upon request the operator would provide the Department with a copy of its report(s) for New York State as required under the EPA"s GHG reporting rule. The operator would provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, records would be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit." Additional requirements[116]: • Gas vented through the flare stack would be ignited whenever possible. The stack would be equipped with a self-ignition device. • A reduced emissions completion, with minimal flaring (if any), would be performed whenever a sales line is available during completion at any individual well or the multiwall pad.
How were these requirements set? When reviewed and at what frequency?	Mechanisms: • EPA Natural Gas STAR participation (federal voluntary program, though New York will require proof of participation)[117] • Subpart W of 40 CFR §98. Under Subpart W (federal mandatory program, reporting to EPA)[118,119] • GHG Emissions Impacts Mitigation Plan (developed by operator and reporting determined by Subpart W of 40 CFR §98) • Leak and detection repair program (permit/regulatory program, reporting to DEC)[120] • RECs permitting/regulatory program where sales line is available (permit/regulatory program, reporting to DEC)
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	• EPA Natural Gas STAR program: no monitoring requirements, but operator will provide GHG mitigation reports to DEC upon request for the period up to and including five years after the well is permanently plugged/abandoned under a DEC permit[121] • Subpart W of 40 CFR §98: see Subpart W table • GHG Emissions Impacts Mitigation Plan: periodic reports to DEC upon request

[116] SGEIS, p. 7-117

[117] See Natural Gas STAR program table for more details.

[118] See Subpart W table for more details.

[119] SGEIS, p. 8-24.

[120] SGEIS, p.7-115.

[121] SGEIS, p.7-117.

Aspect	Details
	• Leak and detection repair program: periodic inspections by DEC personnel and modification to program at operator's discretion • RECs permitting/regulatory program where sales line is available: see RECs table
Notification, reporting and verification requirements	• EPA Natural Gas STAR program: no notification requirements, but operator will provide GHG mitigation reports to DEC upon request for the period up to and including five years after the well is permanently plugged/abandoned under a DEC permit • GHG Emissions Impacts Mitigation Plan: see Subpart W table • Leak and detection repair program: annual report submitted to DEC by March 31 of each calendar year. Report should include inspection results of inspections/repairs completed, explanation of repairs not completed, and should include certification of a company official that all repairs completed were in accordance with company policies, a schedule for repairs completion of remaining leaks, and evaluation/determination of adequacy of existing inspection procedures and schedule to modify procedures and/or increase the number of inspections • RECs permitting/regulatory program where sales line is available: see RECs table
Compliance enforcement / sanctions	• EPA Natural Gas STAR program: no enforcement requirements, but operator will provide GHG mitigation reports to DEC upon request for the period up to and including five years after the well is permanently plugged/abandoned under a DEC permit[122] • GHG Emissions Impacts Mitigation Plan: see Subpart W table • Leak and detection repair program: must make repairs and revise procedures periodically to ensure adequacy of existing inspection procedures and leak repairs • RECs permitting/regulatory program where sales line is available: see RECs table
Links to other policies	http://www.dec.ny.gov/docs/materials_minerals_pdf/rdsgeisapp16270911.pdf Technical Appendix
What measures are shale gas extraction/production companies expected to implement to respond?	Eliminate GHG emissions associated with flaring/venting and leaks to the extent possible by establishing GHG mitigation impacts plan.
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc.)[123]	N/A

[122] SGEIS, p.7-117.

[123] $5-$10 million per well assumed for horizontal well drilling costs. Source: Lipschultz, Marc. "Historic Opportunities from the Shale Gas Revolution." KKR, November 2012: New York, NY.

Aspect	Details
Emission reductions achieved (as a % of on-site fugitive methane emissions)	N/A
Extent to which objectives met	Draft report only. No data available.
Cost/well (€)	See above.
Share of Drilling Costs (%)	See above.
List of potential BMPs to include in GHG Mitigation Plan (only measures related to fugitive/vented emissions included)	Site selection: • Hydraulic fracturing as many wells as possible on a pad with one equipment move • Planning for efficient rig and fracturing equipment moves from one pad to another Transportation: • Using efficient transportation engines [minimal fugitive/vented emissions Well design/drilling: • Extending each lateral wellbore as far as technically and legally possible to reduce the total number of wells required within a spacing unit [limit vented emissions] • Spacing the lateral wellbores for efficient recovery of natural gas • Re-using drilling fluids [no venting in storage tanks] • Drilling overbalanced to limit/prevent venting and/or flaring of CH4 • Ensuring all flow connections are tight and sealed • Flaring methane instead of venting; and • Performing leak detection surveys and taking corrective actions Well production (through Gas STAR): • Implement EPA's Natural Gas STAR BMPs[124] including: ○ Reduce methane emissions from pneumatic devices, compressor rod packing systems, and when taking compressors offline ○ Ensure all flow connections are tight and sealed ○ Performing leak detection surveys and taking corrective actions
Leak and detection repair program details	Program required through either permit or regulation through the operator's GHG emissions mitigation plan, and would include an annual report completed by March 31 of each following year to include the inspection results and any repairs, explanation of repairs not made, certification that repairs made in compliance of company policies and plan, and schedule for completion of repairs for remaining leaks. Minimum requirements include: • "Ongoing site inspection for detected leaks by company personnel. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports.

[124] See Natural Gas STAR template table and see recommendations at: http://www.epa.gov/gasstar/tools/recommended.html

Aspect	Details
	• Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department • All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves, vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet. • For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair. • Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt."

British Columbia Flaring and Venting Guideline, Canada

Aspect	Details
Name of policy / programme	Regulation in British Columbia (BC), Canada
Responsible authority	British Columbia Oil and Gas Commission (BCOGC)
Date policy/ programme adopted	The *British Columbia Oil and Gas Activities Act* (OGAA) was implemented in October 2010 in response to anticipated increased production of natural gas from shale, tight sands and coalbeds. This act updated and consolidated existing regulations and furthered the authority of the Commission with respect to oil and gas activities under other provincial legislation such as the Environmental Management Act, Land Act, Water Act, Heritage Conservation Act, Forest Act, and Forest Practices Code of B.C. Act. The BC act targets elimination of associated gas flaring from producing oil wells, that is economical to conserve. The act also targets reduction of short-term flaring from operations such as well drilling and completions and fugitives that may not be economical to conserve. With specific regard to control of fugitive methane, the *British Columbia Energy Plan*[125] sets a goal to: "eliminate all routine flaring[126] at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce routine flaring by half (50 per cent) by 2011." In February 2008, the Commission released the *Flaring Venting Reduction Guideline for British Columbia* (known as the *'Flaring Guideline'*) (updated Version 4.3 published February 2013).
Objectives	The guide, which was updated in October 2011, ensures that expectations are clear and consistent, and creates a level playing field for operators (BCOGC, 2011a). The goals of the Flaring Guideline are to: • Reduce emissions to air of natural gas, and thereby; • Ensure flaring and incinerating are conducted in a safe and responsible manner; • Permit venting only where conservation or combustion of natural gas is not feasible. See 2011 annual flaring report for progress[127]
Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the country (economic, energy security,	BC has long been a major natural gas producing province, second only to Alberta in Canada. Currently, 60% of natural gas production is 'unconventional' but, as 90% of new wells are for shale gas, this proportion will rise. Shale gas development in northeast B.C., particularly in the Horn River Basin near Fort Nelson, could become a major economic driver for the province. The shale gas industry could develop this resource of trillions of cubic feet of natural gas, resulting in substantial royalties for the provincial government over many decades.

[125] The Clean Energy Act (Bill 17) was introduced on April 28 2010: http://www.energyplan.gov.bc.ca/

[126] Routine associated gas flaring is defined as the continuous flaring of solution gas that is economical to conserve. Associated (solution) gas is gas produced from a well during oil production.

[127] http://bcogc.ca/node/8177/download

Aspect	Details
environmental)	A May 2011 report from the National Energy Board and the B.C. Ministry of Energy and Mines gave a medium estimate of 78 trillion cubic feet (Tcf) of gas that could be developed from the Horn River Basin alone. However, this gas is associated with high concentrations of CO_2, which is normally vented to the atmosphere as the gas is processed to market standards. Other key points: - Low population density in the areas of concern; - Remote locations; - Some of the areas poised for development is First Nations land. These communities have expressed concerns relating to water extraction and air quality.
Key drivers	Environmental concerns & public health
Which on-site GHG fugitive emissions covered?	Fugitive methane from oil and gas producing wells and production facilities
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	**Flaring and Venting Reduction Guideline for British Columbia** *Section 3* This section applies to temporary flaring activities at wells. These activities include well testing, well cleanup and well maintenance/servicing. See Section 8 for temporary venting requirements. The Commission does not consider venting as an acceptable alternative to flaring. If gas is not conserved and gas volumes are sufficient to sustain stable combustion, the gas must be burned. If venting is the only feasible alternative, it must meet the requirements in Section 8. *Section 3.1* 1) Permit holders must evaluate opportunities to use existing gas gathering systems prior to commencing temporary maintenance, well cleanup, or testing operations; that is, in-line testing. 2) In-line testing is mandatory for all wells on private land and wells on Crown Land within 1.25 km of a residence and three km of a suitable pipeline, unless exempted by the Commission (see Directive 2010-03). 3) If in-line testing is not possible, permit holders must design completions and well testing programs to minimise emissions, while ensuring a technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. The Commission Resource Conservation Department, Well Testing Requirements document should be consulted for details on the minimum pressure and deliverability requirements for well testing and the recommended practices to ensure that appropriate information is obtained for conservation and pool management purposes in addition to the requirements of this guideline. *Section 3.3 Oil and Gas Well Test Flaring and Venting Duration Limits* These time limits are per zone and non-consecutive and they do not include shut-in time. These time periods include cleanup, completion, and testing operations: a. crude oil wells/sites6: 72 hours b. gas (non-coalbed methane): 72 hours c. dry coalbed methane development wells (producing less than 1 m3 of water per operating day): 120 hours

Aspect	Details
	d. dry coalbed methane non-development wells (producing less than 1 m3 of water per operating day): 336 hours e. wet coalbed methane wells (producing more than 1 m3 of water per operating day): see Section 3.3(5) below ***f. shale gas development wells: 120 hours*** ***g. shale gas non-development wells: 336 hours*** <u>Extensions to the time limits listed in 1 (f) and (g) are allowed if:</u> <u>a. cleanup of the wellbore is not complete; or</u> <u>b. there have been mechanical problems with the well.</u> <u>The permit holder must document these reasons for extension and keep the information on file for audit by the Commission when requested. The permit holder is not required to obtain permission to extend the flaring/venting beyond the specified time limit listed in #1 (a), (b), (c) or (d) if the reason matches those listed in #2 (a) or (b), but must provide advance notification to the Commission as soon as the permit holder recognizes that the time limit will be exceeded.</u> *Section 8: Venting and Fugitive Emissions Management Requirements* Venting is not an acceptable alternative to conservation or flaring. Venting is the least preferred option and gas should be flared under all except the most exceptional circumstances. *Section 8.1 General Requirements* • All continuous and temporary venting must be evaluated using the decision tree in the appropriate sections of this guideline. • Permit holders must burn all non-conserved volumes of gas if volumes and flow rates are sufficient to support stable combustion. • Vented gas must not constitute a safety hazard. • Venting must not result in offsite odours. *Section 8.2 Limitations of Venting Gas Containing H2S or Other Odorous Compounds* The Commission recommends that permit holders eliminate the venting of gas containing hydrogen sulphide. Wells drilled and facilities constructed after September 1, 2010 must not use gas containing hydrogen sulphide for instrumentation or to provide motive force for pumps unless exempted by the Commission. The Commission recommends any pressure safety valves (PSVs) or blowdown systems be connected to a flare system where such systems are installed. *Section 8.3 Limitations of Venting Gas Containing Benzene* In order to reduce and manage benzene emissions from glycol dehydrators in British Columbia, permit holders must comply with the following requirements, effective June 30, 2007: 1) When evaluating dehydration requirements in order to achieve the lowest possible benzene emission levels, permit holders must use the decision tree process in Appendix A of the Best Management Practices for Control of Benzene Emissions from Glycol Dehydrators, June 2006 (Benzene Control BMP), and retain appropriate analysis documentation for review by the Commission. 2) The permit holder must follow the public consultation process outlined in the Benzene Control BMP. 3) Permit holders must ensure that all dehydrators meet the following benzene emissions limits:

Aspect	Details
	a. If more than one dehydrator is located at a facility or lease site, the cumulative benzene emissions for all dehydrators must not exceed the limit of the oldest dehydrator on site. Modifications may be required to existing units to meet the site limit. b. Any new or relocated dehydrators added to an existing site with dehydrators must operate at a maximum benzene emission limit of 1 tonne/year or less. The cumulative benzene emissions must not exceed the limit of the oldest dehydrator on site. c. For dehydrators that are only in operation for a portion of the year, the benzene emission rate must be prorated. 4) Permit holders must complete a DEOS (Dehydrator Engineering and Operations Sheet), located in Appendix B of the Benzene Control BMP, to determine the benzene emissions from each dehydrator. The sheet must be posted at the dehydrator for use by operations staff and inspected by the Commission. The DEOS must be revised once each calendar year or upon change in operation status of a dehydrator. 5) Permit holders must complete and submit an annual Dehydrator Benzene Inventory List by email in accordance with Section 12 of the Benzene Control BMP. *Section 8.4 Venting of Non-combustible Gas Mixtures* Release of inert gases such as nitrogen and carbon dioxide (CO2) from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases can be vented to atmosphere subject to the following requirement: Non-combustible gas mixtures containing odorous compounds including H2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odorous compounds or underground disposal. *Section 8.5 Surface Casing Vents* Refer to the Well Completion Maintenance and Abandonment Guideline. *Section 8.6 Fugitive Emissions Management* Permit holders must develop and implement a program to detect and repair leaks. These programs must meet or exceed the CAPP Best Management Practice for Fugitive Emissions Management[128]. Permit holders must use pressurized tank trucks or trucks with suitable and functional emission controls when transporting sour fluids from upstream petroleum industry facilities. Source: BCOGC (2013, pp. 54-56)
How were these requirements set? When reviewed and at what	These requirements were set by the BCOGC. The Guidelines currently target routine gas flaring. Long-term objectives are to minimise non-routine flaring.

[128] http://www.capp.ca/getdoc.aspx?DocId=116116&DT=PDF

Aspect	Details
frequency?	
Monitoring requirements	Section 11 of the Guideline sets out measurement and reporting requirements. Note: The Guideline stipulates that "fugitive emissions are NOT to be reported as flared or vented gas as they are considered part of shrinkage."
Notification, reporting and verification requirements	Section 6 of the Guideline sets out notification requirements. Section 11 sets out measurement and reporting requirements. Specifically, sections 11.3 and 11.4 set out how flared and vented gas should be reported. *Section 11.3 Flared and Vented Gas Reporting* Flared and vented gas must be reported as follows: • Flaring associated with well drilling, completions and maintenance must be reported through the Commission online drilling reporting system. A Well Deliverability Test Report must be submitted for deliverability type flow tests, clean-up flows and underbalanced drilling operations • BC-19 form – all flaring and venting of gas at a gas plant • BC-S2 form – flaring from all other facilities, compressors, pipelines, and gas gathering systems • When well test flaring is in excess of 50 mol/kmol H2S (5%), permit holders must complete a Data Confirmation for Flaring Approval Registration and file the report with the Director at the Ministry of Environment in Fort St. John within 30 days of the last day of flaring at the site. For flaring and incineration resulting from under-balanced drilling operations, gas volumes should be reported as net volumes (i.e. gas produced minus gas injected). Similarly, flared gas rates should be representative of net gas obtained near the end of drilling operations. Incinerated gas must be reported as flared gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams at a gas plant that are flared or incinerated as part of normal operations; in these cases, the flared or incinerated acid gas would be reported as acid gas shrinkage, not flared. The permit holder must report all flared or vented gas at the associated reporting facility. It is recommended operators produce a Quality Assurance and Control Manual that includes policies, procedures and an execution plan to ensure measurement data is properly generated, collected and reported to the necessary parties. *Section 11.4 Flaring and Venting Records (Logs)* Permit holders must maintain a log of flaring and venting events and respond to public complaints. Logs must include information on complaints related to flaring and venting events and how these complaints were investigated and addressed. In addition to the information required below, they must at a minimum include:

Aspect	Details
	• Complainant name and contact information • company representative assigned to investigate • Commission representative contacted • If the complaint was resolved Logs must record the following: • Each non-routine flaring and venting incident • The reason it occurred • Any changes implemented to prevent future non-routine events of a similar nature from occurring Logs must include: • Date and time • Duration (in hours) • Gas source or type (e.g., sour inlet gas, acid gas) • Volume for each incident and how the volume information was derived (estimated or metered) Logs must be signed and the name printed legibly by the facility permit holder's representative and kept for a minimum of 12 months. Flaring and venting records (logs) must be made available to an official upon request for each pipeline and facility where flaring and venting occur. Permit holders may retain logs for remote or semi-attended facilities at a central location (e.g., the operator regional office) where public complaints related to the facility in question would normally be received.
Compliance enforcement / sanctions	Enforceable as conditions of permitting
Other environmental control provisions	Operators are required to remove sand from flowback water and as soon as the volumes of gas are sufficient to support combustion, to collect methane for flaring. Furthermore, if the well is located less than 1.5km from the pipeline, the operator is required to connect to the pipeline. The US EPA is considering a similar rule for application in the US. Permit holders of production facilities within 3km of each other or other appropriate O&G facilities (including pipelines) are required to cooperate with the aim of providing economically viable methods for extraction and utilisation or flaring of dissolved gases. The Provincial Cabinet introduced the OGAA General Regulation, Environmental Protection and Management Regulation and the Drilling and Production Regulation (DPR) to protect public safety. Standards addressing safety, environmental impacts, and resource development are found in various sections of the regulations. The DPR includes standards for casing and cementing that, among other benefits, prevent groundwater contamination during hydraulic fracturing. Starting in January 2012, B.C. has required companies to disclose hydraulic fracturing fluid ingredients (e.g. chemicals and additives).
Links to other policies	BC's GHG Reduction Targets Act, passed in 2007, requires a 33% reduction in GHG emissions by 2020, and 80% by 2050. Interim targets of 6% below 2007

Aspect	Details
	levels by 2012 and 18% by 2016 have also been set. There is a carbon tax in British Columba that was introduced in 2008. The current rate for natural gas is $1.50/GJ of natural gas. This acts as a further incentive to reduce flaring.
What measures are shale gas extraction/production companies expected to implement to respond?	See above.
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc.)	No data available
Emission reductions achieved (as a % of on-site fugitive methane emissions)	Overall, industry achieved a 36 per cent decrease in flaring levels between 1996 and 2011 (despite an increase in natural gas production by 76%).[129] The total gas flared per unit of production in 2011 was 4.9m^3/1,000 m^3.
Extent to which objectives met	In 2010 the BC Energy Plan target of eliminating all routine associated gas flaring was achieved (*ibid*).
Cost/well (€)	No data available
Share of Drilling Costs (%)	No data available

[129] BCOGC (2011) Flaring, Venting and Incinerating Summary. Available online here: www.**bcogc**.ca/node/8177/download

New Regulatory Framework to deal with Unconventional Resources, Alberta, Canada

Aspect	Details
Name of policy / programme	New proposed regulatory framework to deal with unconventional resources[130]
Responsible authority	*Energy Resources Conservation Board (ERCB)*
Date policy/ programme adopted	**In draft**

Objectives	The ERCB's new framework is based on two basic principles:
	1. Risk-based regulation—regulatory responses that are proportional to the level of risk posed by energy development.
	2. Play-focused regulation—regulatory solutions that are tailored to an entire "play" to achieve specific environmental, economic, and social outcomes.
	5 key challenges are identified: Water management, surface infrastructure development, subsurface reservoir management, stakeholder engagement, and life-cycle wellbore integrity.
	5 critical outcomes relate to: •
	• Waste management
	  ○ Conserve resources, minimise waste, prevent pollution, and protect the environment and the public.
	• **Air quality**
	  ○ **Ensure that the public and the environment are not measurably affected by adverse air quality.**
	• Conservation
	  ○ Maximize economic recovery of reservoir fluids and conservation of gas.
	  ○ Ensure equal opportunity for all resource owners in receiving an equitable share of production.
	• Orderly development
	  ○ Minimise issues of a regional nature and cumulative effects of oil and gas development.
	• Public safety
	  ○ Ensure that oil and gas activities do not compromise public safety.
	• Information and advice
	  ○ Understand and disseminate information on the extent of resources in the play, production capacity, reserves volumes, and other geological and reservoir characteristics.

Context (e.g. population density, other legislation, geomorphology, public/stakeholder opinion, importance of shale gas to the	Alberta is the biggest hydrocarbon producer in Canada. The productivity of conventional oil and gas wells has declined significantly in recent years. Unconventional resources are a key part of the future of Alberta's energy resource sector as Alberta has significant unconventional resource potential. The ERCB recognises the need to respond to the characteristics of

[130] http://www.ercb.ca/projects/URF/URF_DiscussionPaper_20121217.pdf

Aspect	Details
country (economic, energy security, environmental)	unconventional resources that create new regulatory challenges, such as subsurface areal extent and specific technologies used to extract the oil or gas. This new regulatory approach represents a profound shift in in dealing with unconventional gas from a prescriptive approach to an *outcome-based approach*. Under the proposed framework a play will be delineated based on geological characteristics and an approach will be developed that responds to the specific risk profile of that defined play. As described in the discussion paper: "To manage the effects of development and other issues of a regional nature, a play development plan will use a performance-based regulatory approach, rather than prescribing how regulatory outcomes must be achieved. The ERCB will encourage multi-operator play development plans, in which a group of operators can show how play-specific outcomes are achieved. These plans will offer operators flexibility in how the regulatory outcomes are achieved. The ERCB believes collaboration on play development plans is the most effective way to achieve regulatory outcomes and strongly encourages companies to consider play-focused operator groups early in the development process. Collaboration will allow optimization of infrastructure needs and placement, sharing of information and knowledge, and a one-window approach for communication with stakeholders."
Key drivers	Initially the framework focussed primarily on water resources however due to public concerns and pressure air impacts were built into the framework.
Which on-site GHG fugitive emissions covered?	To be decided
Details of requirements related to fugitive GHG minimisation (direct (e.g. technical standards or emission reduction requirements) or indirect (e.g. controlling environmental/health impacts or resource conservation)	To be decided.
How were these requirements set? When reviewed and at what frequency?	The framework is still under development and is unlikely to come into operation until 2014 (and possibly not until 2015).
Monitoring requirements (calculated, estimated, measured (continuous, periodic, what averaging periods); what pollutants; what standards used?)	To be decided.
Notification, reporting and verification requirements	To be decided.

Aspect	Details
Compliance enforcement / sanctions	To be decided.
Other environmental control provisions	To be decided.
Links to other policies	Alberta has extensive regulations prohibiting venting, and requiring and regulating flaring of gas during clean-up operations. http://www.ercb.ca/directives/Directive060.pdf Directive 060 requires that two key steps are part of the reduction efforts prior to any flaring or venting. The first step is to conduct a Decision Tree Analysis (DTA). The Decision Tree Analysis helps to determine whether there are options to flaring or venting the associated gas. It takes into account public concerns, potential health impacts, environmental impacts and economic alternatives, such as clustering of other flares/vents in a local area and electrical generation. When the Decision Tree Analysis has been conducted and it has been determined in the DTA that other opportunities to conserve the gas are not feasible, an economic evaluation must be conducted to determine whether the associated gas is economically viable to conserve. However, it is recognised that this Directive was designed with the conservation of gas on mind as opposed to dealing with the management of emissions. Furthermore, Directive 060 refers to the CAPP Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities.[131] Directive 060 states that operators must meet or exceed the strategies for achieving cost-effective reductions in these emissions outlined in the BMP. Directive 017: Measurement Requirements for Upstream Oil and Gas Operations, states how companies accurately measure associated gas.[132]
What measures are shale gas extraction/production companies expected to implement to respond?	To be decided.
Data on costs of expected mitigation measures (per well, as a % of drilling costs, etc.)	No data

[131] http://www.capp.ca/getdoc.aspx?DocId=116116&DT=PDF

[132] http://www.ercb.ca/directives/Directive017.pdf

Appendix B – Assessment of mitigation options

1. Reduced Emission Completions (RECs)

Introductory information: Introductory information (mutually exclusive of RECs on Low Pressure Wells Option 10 and RECs on Exploratory Wells Option 11)			
Name of technology/practice	Reduced Emission Completions (RECs)		
Supplier(s)	Global Suppliers: Weatherford, Baker Hughes		
Which fugitive GHG emission source does it target?	1) Flowback Venting during Hydraulically Fractured Well Completions 2) Flowback Venting during Hydraulically Fractured Well Workovers		
Which primary GHG does it target?	Methane (CH_4)		
Brief details on how it works	RECs capture gas and condensate produced during well completions and well workovers with hydraulic fracturing during the flowback of the fracture fluids. During a gas well completion with hydraulic fracturing, fracture fluid (primarily water and sand) are injected into the well and reservoir at higher pressure. Subsequently, natural gas from the fractured reservoir pushes the fractured fluid out of the well bore (i.e., flowback). The flowback is a mixture of natural gas, condensate, and saturated fracture fluids and is not suitable for gathering pipelines. Operator's need to remove the majority of the fracture fluids to prepare the well for connection to a gathering pipeline. The flowback is typically flown into a pit where the gas is vented and the fracture fluids are collected. To capture the gas, portable equipment (REC) that is specially designed and sized for the initial high rate of water, sand, and gas flowback is brought on site. The objective is to separate the gas from the solids and liquids produced during the high-rate flowback, so that the initially produced gas can be delivered into the sales pipeline. A typical REC system will include a sand trap to remove the finer solids present in the production stream. It will also include plug catchers that are used to remove any large solids such as drill cuttings that could separate other separation equipment. Finally, a three phase separator is used to remove the free water and condensate from the gas. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. The REC is kept at the well site until the natural gas is the appropriate spec (i.e., low concentration of fracture fluid) to inject into the gathering pipeline. Depending on the gas gathering system, it may be necessary to dehydrate (remove water from) the produced gas before it enters the sales pipeline		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	90%	90%	N/A
Key factors affecting this	Depends on whether RECs are used in conjunction with flares. Flares would worsen REC CO_2 mitigation.	Depends on whether RECs are used in conjunction with flares. Flares improve REC methane mitigation.	Assumes RECs are not used in conjunction with flares. Flaring natural gas emits N_2O.

Typical average methane recovery	90%
Key factors affecting this	Gas pressure: The extent to which an REC is implemented depends on if the well is producing natural gas at pressures high enough above the gathering pipeline pressure. The pressure of the natural gas entering a REC decreases resulting in a lower pressure natural gas exiting the REC. The pressure of the natural gas exiting the wellhead must be high enough to incur the "pressure drop" along the REC and be higher than the gathering pipeline pressure. Otherwise, the produced natural gas will not flow into the gathering pipeline. Gas composition: RECs are designed to tolerate specific volumes of sand and liquids. The composition of the natural gas exiting the wellhead will determine if an REC is feasible. Also, the economic case for an REC is heavily driven by the recovery of valuable NGLs. NGL-rich natural gas is more likely to be captured. Access to Gas Gathering Pipeline: RECs require a gathering pipeline to collect and distribute the recovered gas either for sale or for processing.
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[133] (e.g., Hexane, Hydrogen Sulfide) Reduced Flaring Natural Gas Liquids (propane, butane, pentane, hexane, heptane). This is an additional revenue stream. Abatement efficiency for secondary emissions is 90%.
Energy/resource consumption	None
Indirect GHG emissions resulting from this	No indirect GHG emissions. Although, flares are commonly used in combination with RECs to improve the overall efficiency of mitigating methane from hydraulically fractured gas well completion flowback venting. If flares are used, indirect CO_2, N_2O, CO, and PM emissions occur.
Costs	
CapEx per well (2008 U.S. dollars):	Purchase REC Case: $575,846
OpEx per well (2008 U.S. dollars):	Purchase REC Case: - Transportation and Set Up Cost: $691 per completion - Labor Costs: $1,244 per completion [134] Rent REC Case: - Transportation and Set Up Cost: $691 per completion - Equipment Rental and Labor Cost: $806 - $7,486 per day[135] *Well flowback can last from 1 to 30 days. Potential Additional Cost: - Buying Gas to Inject into Well: 21,000 m^3/completion * Price of Natural Gas *It may be necessary to inject gas into the well to compensate for the added

[133] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[134] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

[135] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

	back pressure caused by the REC.
Revenue per well and per unit production	$810,000 - $1,890,000 per year (with purchased equipment). Assuming 25 completions per year. $32,400 - $75,600 per completion (with rented equipment)[136]
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Assumed capture of 7,600 m^3 (270,000 Mcf) per year (with purchased equipment), assuming 25 completions per year. Assumed capture of 300 m^3 (10,800 Mcf) per completion (with rented equipment). For revenue, gas price ranged from $3 to $7 per Mcf.
Factors affecting capital cost, operating cost, revenue	Availability of REC equipment, availability of pipeline, pressure of produced gas, price of gas.
Other key details	
Reliability in operation	There are multiple factors that determine REC reliability. Each REC application is subject to: • The producing reservoir which affects flowback pressure, gas composition, duration of flowback, and steady or erratic flow behavior. • The fracture fluid pumped down the well which includes: total volume received during flowback, concentration of water and sand in flowback. RECs are designed to handle a maximum flow rate of solids and liquids.
Applicability	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 that management practices in the EU may differ from those in the U.S. For example, in the U.S. many operators flow hydraulic fracture fluid into open-lined pits during a well completion. Operators in the EU may choose, for example, to flow hydraulic fracture fluid into temporary tanks.
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	As REC equipment becomes more widely available and experience with implementing them improves, the associated capital and operating costs will come down. This will increase the profitability of using REC technology.
Experience (number of applications)	This technique has seen widespread use in the U.S. since the early 2000s.
References for further info	http://epa.gov/gasstar/documents/reduced_emissions_completions.pdf
Feedback from operators and regulators on performance	Using RECs have been one of the most popular options to reduce methane emissions under the U.S. EPA's Natural Gas STAR Program. Between 2000 and 2009 emissions reductions from RECs (as reported to Natural Gas STAR) have increased from 5,663 TCM (200 MMcf) to over 6.17 billion m^3 (218,000 MMcf).

[136] Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, U.S. EPA Lessons Learned, P.1.

Limitations	Not applicable to all hydraulically fractured wells (low pressure shale gas wells and exploratory[137] wells are not good candidates for RECs). Below is a list of limitations for implementing RECs: • RECs can and have been implemented on low pressure wells, however, the cost is greater. Operators, in addition to the REC capture system would need to inject a high pressure stream of natural gas into the completed well to raise the pressure of the well during the completion process. • The pressure of the gathering system downstream. High pressure gathering systems may prohibit REC use, as RECs reduce the pressure of the gas existing the well. • Proximity to existing gas gathering infrastructure. Exploratory wells are typically not drilled next to existing infrastructure. Lack of existing gas gathering infrastructure may make REC applications too costly or not feasible. • The composition of the recovered natural gas may not be suitable for injection into the gathering system. High concentrations of CO_2 or H_2S in the gas stream may prohibit operators from recovering the gas.

2. Conducting Directed Inspection and Maintenance

Introductory information	
Name of technology/practice	Conducting Directed Inspection and Maintenance
Supplier(s)	Global Suppliers: FLIR®, Opgal, GasCam®
Which fugitive GHG emission source does it target?	Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources.
Which primary GHG does it target?	Methane (CH4)
Brief details on how it works	Unintentional equipment leaks may arise due to normal wear and tear, improper or incomplete assembly of components, inadequate material specification, manufacturing defects, damage during installation or use, corrosion, fouling and/or annual temperature change cycles. Directed inspection and maintenance (DI&M) program concentrates on components that are prone to leak enough methane to make repairs cost-effective. Through specialized infrared (IR) cameras and a trained team, hydrocarbon emissions can be detected throughout a facility. After identifying leaking equipment, repairs are made in cases where the leak poses a safety threat or when the repairs are economically feasible (i.e. benefits outweigh the costs).

[137] Exploratory Wells are wells drilled to test the viability of new or young fields. Exploratory wells are typically drilled in remote locations further away from existing gathering infrastructure. Without a gathering system nearby it is either not feasible or very expensive to implement an REC.

Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	Up to 100% (assuming the leak is repaired)	Up to 100% (assuming the leak is repaired)[138]	n/a
Key factors affecting this	Currently, there is no data to determine the effectiveness of a DI&M programs at well sites. The effectiveness of the program will vary by site and company. The effectiveness will vary depending on the number of leaks found, repaired, and the frequency of inspection.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[139] (e.g., Hexane, Hydrogen Sulfide). Abatement efficiency for secondary emissions is up to 100%.		
Energy/resource consumption	Transportation fuel to move monitoring crew from one site to another.		
Indirect GHG emissions resulting from this	Combustion emissions from transportation.		
Costs			
CAPEX	In-House Program Case: $100,000 (IR Camera)		
OPEX	In-Hour Program Case: - Labor hours for conducting DI&M: $1/component surveyed -Repair Cost: $10 - $5,600 *depending on component Contractor Case: - Labor hours for conducting DI&M: $1/component surveyed -Repair Cost: $10 - $5,600 *depending on component		
Revenue per well and per unit production	$1,200 - $2,700		
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	The IR camera will be the bulk of capital costs, in addition to the costs to train a team to conduct DI&M. O&M costs include the labor costs associated the leak detection and repair team.		
Factors affecting capital cost, operating cost revenue	Revenue range based on gas price range ($3/Mcf to $7/Mcf)		
Other key details			
Reliability in operation	Reliability of DI&M program is dependent on the quality of the monitoring and repair. • Monitoring needs to be thorough and complete		

[138] From our experience, most of the companies we dealt with were not aware of the leaks they had on site. Therefore, this is considered extra abatement.

[139] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

	• Repairs need to be high quality and provide lasting solutions to the leak.
Technology maturity	*Commercially available*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IN: Intermediate – 1 – 5 years. Commercially available, but major retro-fit or newbuild required.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	Infrared cameras are the more cost effective means to detect equipment leaks at a large facility. Given that infrared cameras are a relatively new technology, costs are expected to drop with time.
Experience (number of applications)	Leak detection has been a common practice for processing plants in the U.S. due to federal regulations. Federal regulations require production operators to monitor tank vents, quantify, and report emissions but there is no requirement for repair.
References for further info	EPA (2003). *Lessons Learned: Directed Inspection and Maintenance.* <www.epa.gov/gasstar/documents/ll_dimgasproc.pdf>
Feedback from operators and regulators on performance	N/A
Limitations	An operator may own hundreds of wells that that span hundreds of miles, this will make the process of leak detection and repair cost prohibitive in the production segment.

3. Convert Natural Gas-Driven Chemical Pumps to Instrument Air Driven or to Electrical Pumps

Introductory information	
Name of technology/practice	Convert Natural Gas-Driven Chemical Pumps to Instrument Air Driven or to Electrical Pumps
Supplier(s)	U.S. Suppliers: Blair Air Systems
Which fugitive GHG emission source does it target?	Natural gas driven pneumatic pump venting
Which primary GHG does it target?	Methane (CH4)
Brief details on how it works	Natural gas driven pumps (i.e., positive displacement pumps for moving liquids) are driven using the mechanical energy of pressurized natural gas. Without electricity nearby, operators drive their pumps using pressurized natural gas from their well(s). The most common application of natural gas driven pumps at well sites is for chemical injection and to circulate the glycol in a dehydrator. Natural gas driven pumps however vent the natural gas used to drive them. Venting of methane as well as VOCs and HAPs from pneumatic pumps is eliminated by converting the pumps from being natural gas driven to either instrument air-driven or electric. Instrument air pumps require that the operator install an air compressor to pressurize air to drive the pumps. Electric pumps may either require installing a generator or

	evaluating if a connection to the grid is feasible.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	100%	100%	N/A
Key factors affecting this	Dependent on if the air-compressor or electric generator is powered by hydrocarbons.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	VOC and HAP[140] (e.g., Hexane, Hydrogen Sulfide) emissions are avoided, if the gas typically used comes straight from the well. Abatement efficiency for secondary emissions is 100%.		
Energy/resource consumption	*Instrument Air Pneumatic Pumps* require installing an air-compressor which can be driven by combusting hydrocarbons, electricity, or renewable energy (e.g., solar). *Electric Pumps* require finding a source or electricity. This may either be installing an electric generator onsite or establishing a connection to the local power grid.		
Indirect GHG emissions resulting from this	Where hydrocarbons are combusted to drive either an air-compressor or electric generator, N_2O will be emitted along with CO_2, NO_x, and CH_4.		
Costs			
CapEx per unit	The capital cost for converting to instrument air is the cost to install a pipe to a pump, connected to the air compressor. $1,000 - $10,000 per pump[141]		
OpEx per unit	$100 – $1,000[110] Incremental cost to operate the instrument air or electric pumps.		
Revenue per unit	$550 - $18,600 (Converting to electric) ($3-$7 per Mcf)		
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	The capital cost estimates are based on a natural gas operator's experience replacing natural gas driven pneumatic pumps on dehydrators. The total cost to convert a gas pneumatic glycol circulation pump to instrument air would include installation of piping and an appropriate control system between the existing instrument air system and the glycol pump if the driver is independent of the circulation pump. If the driver is separated from the pump by O-rings, then the pump would have to be replaced as well. Another natural gas operator replaced failed pneumatic pumps, on an ongoing basis, with solar-charged electric pumps at a cost of approximately $2,000 per pump. On-going operating and maintenance costs have not been quantified, but appear to be lower for the solar-charged electric pumps compared to the natural gas-driven pumps		
Factors affecting capital cost, operating cost revenue	Revenue ranges are based on a range of gas prices ($3/Mcf - $7/Mcf). The purpose of the pneumatic pumps (e.g., dehydrator or chemical injection) play a large role on what emission reduction opportunities are available.		

[140] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[141] Convert Natural Gas Driven Pneumatic Pumps, U.S. EPA Lessons Learned, P.1.

Other key details	
Reliability in operation	Weather and climate can affect the reliability of solar powered electric-driven pumps.
Applicability	Facilities can convert their pumps to be instrument air-driven if they have excess capacity in their instrument air systems. For converting to electric, the facility must be electrified or have sufficient sunlight for solar power.
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	Improvements in micro solar panel applications can reduce the cost and improve the efficiency and reliability of solar powered chemical injection pumps.
Experience (number of applications)	NA
References for further info	http://www.epa.gov/gasstar/documents/ convertgasdrivenchemicalpumpstoinstrumentair.pdf
Feedback from operators and regulators on performance	One industry contact converted 2,000 glycol pumps to solar-powered electric pumps and saved 28,300 m^3/day.
Limitations	When converting to solar powered electric pumps, weather leading to poor sunlight availability can lead to issues in power supply.

4. Installing Plunger Lifts Systems in Gas Wells

Introductory information			
Name of technology/practice	Installing Plunger Lifts Systems in Gas Wells		
Supplier(s)	U.S. Suppliers: PCS Ferguson, Mega Lift Systems Global Suppliers: Schlumberger, Weatherford		
Which fugitive GHG emission source does it target?	Well venting for liquids unloading		
Which primary GHG does it target?	Methane (CH4)		
Brief details on how it works	Accumulated fluids in mature gas wells can impede and sometimes halt gas production. Gas flow through the well is often maintained by removing accumulated fluids through venting the well to atmospheric pressure (referred to as “blowing down” the well). Installing a plunger lift system is a cost-effective alternative for removing liquids. Plunger lift systems avoid venting a well to the atmosphere, with the added benefit of increasing production.		
Performance	CO_2	CH_4	N_2O

Typical abatement efficiency for key GHGs (primary abatement metrics), %	100% (assuming the gas lifting the plunger lift is recovered to a sales line)	100% (assuming the gas lifting the plunger lift is recovered to a sales line)	N/A
Key factors affecting this	Depth and pressure of well.	Depth and pressure of well.	
Typical average methane recovery efficiency	U.S. industry partners have reported an annual gas savings averaging 17,000 m^3 per well by avoiding blowdown and an average of 850 m^3 per year by eliminating workovers.		
Key factors affecting this	The savings will be impacted by the venting frequency of the well and the pressure of the well. The potential amount of methane available for recovery will increase as the pressure and the venting frequency increase.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[142] (e.g., Hexane, Hydrogen Sulfide) Natural Gas Liquids (NGLs) Reduced Flaring Abatement efficiency for secondary emissions is 100% (assuming the gas lifting the plunger lift is recovered to a sales line).		
Energy/resource consumption	None		
Indirect GHG emissions resulting from this	None		
Costs			
CapEx per well (2006 U.S. Dollars)	$1,900 to $7,800 per plunger lift system; this includes installing the piping, valves, controller and power supply on the wellhead and setting the down-hole plunger bumper assembly assuming the well tubing is open and clear.[143]		
OpEx per well (2006 U.S. Dollars)	$700 to $1,300 per year – Plunger lift maintenance requires routine inspection of the lubricator and plunger. Typically these items need to be replaced every 6 to 12 months.[144]		
Revenue per well	$14,100 - $54,750 per year(at $3 per Mcf) $23,500 - $91,250 per year (at $5 per Mcf) $32,900 - $127,750 per year (at $7 per Mcf)		
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	A plunger lift system requires at least 11 m^3 of gas per barrel of fluid gas per 300 m of depth, also a shut-in wellhead pressure that 1.5 times the sales line pressure.		
Factors affecting capital cost, operating cost revenue	The most significant benefit of plunger lift installations is the resulting increase in gas production that translates to added revenue revenues.		
Other key details			
Reliability in operation	There are multiple factors that determine plunger lift reliability. Each plunger lift application is subject to: The well production; 11 m^3 of gas per barrel of fluid per 300m of depth is required. Wells must have a shut-in wellhead pressure that is 1.5 times the sales line		

[142] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[143] Installing Plunger Lift Systems in Gas Wells, U.S. EPA, P.3.

[144] Ibid, P.4.

	pressure.
Applicability	All gas wells with liquids loading – typically low pressure wells or mature wells.
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	The number of mature shale gas wells is expected to increase in the near future, this means that a greater number of plunger lifts will be required.
Experience (number of applications)	Weatherford estimates that there are 150,000 plunger lifts currently installed in the U.S. According to the U.S. Inventory of Natural Gas Systems 2010, this translates to approximately 31% of all non-associated gas wells in the U.S.
References for further info	http://epa.gov/gasstar/documents/ll_plungerlift.pdf
Feedback from operators and regulators on performance	Industry (Natural Gas STAR partners) has reported significant economic benefits and methane emission reductions from installing plunger lift systems in gas wells.
Limitations	Plungers may get stuck in the well, but this can be avoided by properly analyzing the geology of the well, and the scaling buildup inside the well.

5. Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators

Introductory information	
Name of technology/practice	Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators
Supplier(s)	U.S. Suppliers: COMM Engineering USA
Which fugitive GHG emission source does it target?	Venting of methane from Dehydrator Re-boiler
Which primary GHG does it target?	Methane (CH4)
Brief details on how it works	Reducing glycol circulation rates reduces methane emissions at negligible cost by reducing the amount of absorbed methane during dehydration. Glycol dehydrators remove water from natural gas by contacting the natural gas with triethylene glycol (TEG). TEG has a strong affinity for water but also a slight affinity for methane. After contact, the water and methane-rich TEG is heated in a re-boiler to remove the water and methane. The lean-TEG is then re-circulated to contact the natural gas. The water vapor and methane released in the re-boiler are typically vented. In many cases, operators will increase the TEG circulation rate to remove more water from the natural gas,

	however; this also results in more methane being removed from the natural gas stream. Subsequently, reducing the TEG circulation rate will decrease the volume of methane vented from the dehydrator re-boiler. Installing flash tanks separators on glycol dehydrators will recover methane that would otherwise be vented, and instead recycles the methane as fuel, or sends it to the compressor suction. Flash tank separators recover the methane in the rich-TEG solution by dramatically decreasing the pressure of the TEG after contacting the natural gas. The decrease in pressure allows methane to come out of solution and be recovered for use as fuel or injected into a sales pipeline.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	N/A	95%	N/A
Key factors affecting this	Dependent on the optimal glycol circulation rate as well as the type of TEG circulation pump. Dehydrators with flash tank separators need a pump to move the glycol from the re-boiler back to the contactor. These pumps can either be electric or energy transfer pumps. Energy transfer pumps use the mechanical energy from the rich TEG and some of the high pressure natural gas feed to drive the pump. Since energy transfer pumps use natural gas as a driver, they will emit more methane than electric pumps.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[145] (e.g., Hexane, Hydrogen Sulfide)		
Energy/resource consumption	Circulation pump driven by electricity or natural gas.		
Indirect GHG emissions resulting from this	Combustion emissions from the electricity/natural gas consumed to drive the pumps.		
Costs			
CapEx per unit (2006 U.S. Dollars)	$0 (Reducing glycol circulation rate) $6,500 - $18,800 (Installation of flash tank separator and reducing glycol circulation rate)[146]		
OpEx per unit (2006 U.S. Dollars)	Operating costs include the labor for optimizing and checking the circulation rate. Operating costs for flash tank separator are negligible.		
Revenue per unit	$1,960 - $275,000 (Reducing glycol circulation rate) $3,573 - $75,019 (Installing Flash Tank Separator)		
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Flash tank separators are manufactured in two designs – horizontal and vertical. In general, operations that have significant volumes of NGLs in their gas streams should use a 3-phase horizontal separator with a retention time of 10 to 30 minutes. Operations with low NGL volumes should use a 2-phase vertical separator with a 5 to 10 minute retention time.		

[145] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[146] Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, U.S. EPA Lessons Learned, P.1.

Factors affecting capital cost, operating cost revenue	Costs of the flash tank separators can range between $3,375 and $6,751, uninstalled, depending on flash tank design and size. If the required size exceeds the largest standard flash tank available, operators can either have a custom tank built, install multiple flash tanks in parallel, or install a separate NGL accumulation tank. Installation costs depend on the location, terrain, foundation, weather protection, NGL accumulation and pickup compatibility, and automation and instrumentation. Revenue ranges based gas price range ($3/Mcf to $7/Mcf). The flash tank separator revenues vary depending on the type of pump installed (energy exchange versus electric) and the glycol circulation rate (150 gal/hr versus 450 gal/hr).
Other key details	
Reliability in operation	Optimizing the glycol circulation rate is as reliable as the calculation in determining the rate. The optimum rate is a function of the gas flow rate, the water content of incoming gas, and the desired water content of outgoing gas. Problems can arise if the circulation rate is too low; therefore a certain amount of over-circulation is desired. Rates can cause issues with tray hydraulics, contactor performance, and fouling of glycol-to-glycol heat exchangers.
Applicability	All facilities with glycol dehydrators.
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	N/A
Experience (number of applications)	There is a U.S. federal regulation requiring operators with large dehydrators to prevent the venting of HAPs from dehydrator re-boilers. The regulation estimated that about 33% of the dehydrators in the United States would be captured under the ruling.[147]
References for further info	http://epa.gov/gasstar/documents/ll_flashtanks3.pdf
Feedback from operators and regulators on performance	Over time, the seals on gas-powered energy-exchange pumps can leak, contaminating the lean glycol and reducing the dehydration effectiveness. Operators should not compensate for the contaminated glycol by increasing the circulation rate. Instead, the energy-exchange pump should be evaluated for repair or replacement.
Limitations	Operators must take care when reducing their circulation rate that they are still meeting their pipeline specifications for water content.

[147] NESHAP: Oil and Natural Gas Production and Natural Gas Transmission and Storage - Background Information for Prosposed Standards, EPA-453/R-94-079a

6. Convert High-bleed Pneumatic Devices to Low-bleed

Introductory information			
Name of technology/practice	Convert High-bleed Pneumatic Devices to Low-bleed		
Global Supplier(s)	Global Suppliers: Fisher (Emerson), CVS Controls Ltd., Honeywell		
Which fugitive GHG emission source does it target?	Natural gas pneumatic device venting		
Which primary GHG does it target?	Methane (CH4)		
Brief details on how it works	Pneumatic devices powered by natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Pneumatic devices, as part of their normal operation, vent natural gas to the atmosphere. The volume of natural gas vented varies by model and age. High-bleed pneumatic devices vent over six standard cubic feet of CH4 per hour per device. The average high-bleed pneumatic device vents 330 standard cubic feet CH_4 per day per device. Low-bleed pneumatic devices vent six or less standard cubic feet of CH4 per hour per device. Low-bleed pneumatic devices vent on average to 52 cubic feet CH_4 per day per device. By retrofitting or switching high-bleed pneumatic devices to low-bleed pneumatic devices, emissions are reduced. Not all pneumatic device applications are appropriate for low-bleed devices, but field experience has shown that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	84%	84%	N/A
Key factors affecting this	See below.	See below.	
Typical average methane recovery efficiency	84% (per device)		
Key factors affecting this	Methane abatement efficiency is dependent upon the initial bleed rate of the high-bleed rate device. Bleed rates will vary with pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[148] (e.g., Hexane, Hydrogen Sulfide)[149] Abatement efficiency for secondary emissions is 84% for each high-bleed pneumatic device replaced.		
Energy/resource consumption	None		
Indirect GHG emissions resulting from this	None		

[148] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[149] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

Costs	
Capex per unit (2006 U.S. Dollars)	$210 to $340 (Change to low-bleed at end of life) $1,850 (Early replacement of high-bleed unit) $675 (Retrofit)[150]
Opex per unit (2006 U.S. Dollars)	N/A
Revenue per unit	$150 - $1,400 (Change to low-bleed device at end of life) $780 - $1,820 (Early replacement of high-bleed unit) $690 - $1,610 (Retrofit)
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Assumed 1,416 – 566 m^3gas/year reduced (Change to low-bleed device at end of life) Assumed 7,362 m^3 gas/year reduced (Early replacement of high-bleed unit) Assumed 6,513 m^3 gas/year (Retrofit) For revenue, gas price ranged from $3 to $7 per Mcf
Factors affecting capital cost, operating cost revenue	Number of existing pneumatic devices and age of existing pneumatic devices.
Other key details	
Reliability in operation	For applicable wells, technology is highly reliable
Applicability	For all wells which have high-bleed pneumatic devices
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	None. Low-bleed pneumatics are estimated to make up more than half the population of pneumatic devices and 90 percent of new pneumatic device sales.
Experience (number of applications)	564,500 low-bleed pneumatic devices have been installed in the U.S. as of 2010. Source: *Inventory of Greenhouse Gas Emissions and Sinks 1990-2010*. Assumed 65% of pneumatic devices are low-bleed.
References for further info	http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf
Feedback from operators and regulators on performance	One Natural Gas Partner replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, the Partner estimated a total methane emissions reduction of 1,404,516 m^3 per year.
Limitations	Low-bleed pneumatic devices are lower pressure devices that may not suitable for all pneumatic device applications. Some applications for pneumatic controllers may only be feasible with high-bleed pneumatics.

[150] Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry, U.S. EPA Lessons Learned, P.1.

7. Rod Packing Replacement in Reciprocating Compressors

Introductory information			
Name of technology/practice	Rod Packing Replacement in Reciprocating Compressors		
Supplier(s)	U.S. Suppliers: Aavolyn, Compressor Engineering Corp (CECO)		
Which fugitive GHG emission source does it target?	Reciprocating compressor rod packing systems		
Which primary GHG does it target?	Methane (CH4)		
Brief details on how it works	All packing systems leak under normal operation. The amount of emissions is dependent on the cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft rod. A timely schedule is developed for the economic replacement of rod packing systems in reciprocating compressors to mitigate methane emissions and increase savings.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	N/A	55% (assuming a replacement schedule of 3 years)	N/A
Key factors affecting this		The timing of replacement will affect the abatement efficiency.	
Typical average methane recovery efficiency	55%		
Key factors affecting this	The timing of replacement will affect the abatement efficiency.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[151] (e.g., Hexane, Hydrogen Sulfide)[152] Abatement efficiency for secondary emissions is 55% (assuming a replacement schedule of 3 years).		
Energy/resource consumption	None		

[151] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[152] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

Indirect GHG emissions resulting from this	None
Costs	
CapEx per unit production (2006 U.S. dollars)	$1,620 every three years (industry average replacement timeline) or $540/year.[153]
OpEx per unit production (2006 U.S. dollars)	Operating costs include labor to replace packing systems, measuring leak rates, and determining economic timeline for packing replacement.
Revenue per unit production	$2,595 - $6,055 (assuming gas prices that range from $3 - $7 per Mcf)
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Capital costs include the cost of flexible rings which fit around the shaft to create a seal against leakage, as well as the packing cups which hold the packing rings in place.
Factors affecting capital cost, operating cost revenue	Factors affecting capital cost include rod dimension and type of rod, as well as the material of replacement rings, cups, and the rod itself.
Other keys	
Reliability in operation	Rods need to be aligned properly and rings need to be fitted properly for the packing system to be effective. A new packing system, may will emit approximately 0.31-0.34 cubic meters per hour (11 to 12 standard cubic feet per hour). However; as the system ages, the leak rates will increase from wear on the packing rings and piston rod.
Applicability	All reciprocating compressor rod packing systems
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	Carbon-impregnated Teflon is gradually replacing bronze metallic rings. Their prices are similar however the Teflon lasts about one year longer than conventional bronze rings. Upgraded piston rods coated with tungsten carbide have proven to increase service life for rods by reducing wear.
Experience (number of applications)	Rod packing replacement is an industry accepted method for savings and reducing methane emissions from reciprocating compressors.
References for further info	http://epa.gov/gasstar/documents/ll_rodpack.pdf
Feedback from operators and regulators on performance	Operators have provided a systematic approach to determining the economic replacement threshold for rod packing replacement.
Limitations	None.

[153] Reducing Methane Emissions from Compressor Rod Packing Systems, EPA Natural Gas STAR Lessons Learned, P.1.

8. Installing Vapour Recovery Units (VRUs) on Storage Tanks

Introductory information			
Name of technology/practice	Installing Vapour Recovery Units (VRUs) on Storage Tanks		
Supplier(s)	U.S. Suppliers: Flogistix, Global Suppliers: Exterran, OPW		
Which fugitive GHG emission source does it target?	Vented emissions from crude oil storage tanks		
Which primary GHG does it target?	Methane (CH_4)		
Brief details on how it works	Crude oil storage tanks are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites (some shale gas wells have associated crude oil production). The crude oil experience a drop in pressure as it is transferred to the crude oil storage tank. Due to this drop in pressure, light hydrocarbons vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. These vapors are vented to the atmosphere to avoid pressure build-up. VRUs are installed on crude oil storage tanks to prevent these vented emissions.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	95%	95%	N/A
Key factors affecting this	The reliability of the suction scrubber and compressor.	The reliability of the suction scrubber and compressor.	Assuming the storage tank vented emissions was not previously flared.
Typical average methane recovery efficiency	95%		
Key factors affecting this	The reliability of the suction scrubber and compressor.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	VRUs capture many other btu-rich hydrocarbon vapors that would otherwise be vented to the atmosphere. VRUs also eliminate VOC and HAP (e.g., Hexane, Hydrogen Sulfide)[154] emissions. Abatement efficiency for secondary emissions is 95%.		
Energy/resource consumption	Electricity to drive the rotary compressor which creates a suction line.		
Indirect GHG emissions resulting from this	None		
Costs			

[154] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

Capex per per unit (2006 U.S. Dollars)	$35,738 - $103,959[155]
Opex per per unit (2006 U.S. Dollars)	$7,367 - $16,839[118]
Revenue per unit	$13,965 - $638,400 ($3-$7 per Mcf)
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	The capital costs are based on the actual capital cost of equipment plus the cost to install/implement the system. The higher the capacity of the system the more expensive the capital cost. The operating costs increase with increased system capacity.
Factors affecting capital cost, operating cost revenue	Capital costs range based on throughput capacity of the VRU and the horsepower of the compressor. The higher the throughput, the higher the horsepower of the compressor. The operating costs range based on the location of the VRU (sites in extreme climates means more wear), electricity costs, and the type of oil produced. For instance, paraffin based oils clog the VRUs and require more maintenance.
Other key details	
Reliability in operation	VRUs capture approximately 95% of flashing losses, from storage tanks. VRUs success depends on the lines connecting the tanks to the compressor, as well as the compressor which creates the suction.
Applicability	Natural gas wells with high condensate production. On average, four tanks are connected to a VRU – therefore; the presence of multiple crude oil storage tanks makes this technology more economically favorable.
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	VRUs can also be applied to other venting equipment in production, including pneumatic devices.
Experience (number of applications)	Currently, there are between 7,000 to 9,000 VRUs installed in the U.S. oil production sector.
References for further info	http://epa.gov/gasstar/documents/ll_final_vap.pdf
Feedback from operators and regulators on performance	Industry has reported significant savings and revenue from recovering and marketing the vapors while at the same time substantially reducing methane and HAP emissions. Industry contacts have reported paybacks periods in as little as 2 months due to significant savings.
Limitations	None other than the cost of installment.

[155], Installing Vapor Recovery Units on Storage Tanks, U.S. EPA Lessons Learned, P.1

9. Replacing Wet Seals with Dry Seals in Centrifugal Compressors

Introductory information: (mutually exclusive from Installing a Wet Seal Degassing Recovery System – see below)			
Name of technology/practice	Replacing Wet Seals with Dry Seals in Centrifugal Compressors		
Supplier(s)	Global Suppliers: Dresser-Rand, Flowserve, John Crane		
Which fugitive GHG emission source does it target?	Centrifugal compressor wet seal emissions		
Which primary GHG does it target?	Methane (CH4)		
Brief details on how it works	Centrifugal compressors are widely used in the production of natural gas. Seals on the rotating shafts of centrifugal compressors prevent the high-pressure natural gas from escaping the compressor casing. Traditionally, these seals used high-pressure oil (wet seals) as a barrier against escaping gas. Dry seals, which use high pressure gas instead, emit less while lowering power requirements and improving compressor performance and reliability.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	97%	97%[156]	N/A
Key factors affecting this	See below.	See below.	
Typical average methane recovery efficiency	97%		
Key factors affecting this	The compressor pressure must be below 34.5 bar and the temperature must be below 148.9^{o} C. Furthermore; compressors should not be towards the end of their life.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	VRUs capture many other btu-rich hydrocarbon vapors that would otherwise be vented to the atmosphere. VRUs also eliminate VOC and HAP (e.g., Hexane, Hydrogen Sulfide)[157] emissions. [158] Abatement efficiency for secondary emissions is 97%.		
Energy/resource consumption	None		

[156] : Typical wet gas seal leakage ranges from 40 to 200 scfm. , Dry seals leak at a rate of 0.5 to 3 scfm.

[157] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[158] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

Indirect GHG emissions resulting from this	None
Costs	
CapEx per unit production (2006 U.S. Dollars)	$162,000 (2 dry seals) $162,000 (Engineering, equipment installation) Total = $324,000[159]
OpEx per unit production (2006 U.S. Dollars)	$14,100[160]
Revenue per unit production	$135,360 - $315,840/year ($3 - $7 per Mcf)
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Dry seals cost based on $13,500/shaft-inch, with testing. Capital costs assume 6-inch shaft beam compressor. The engineering and equipment installation accounts for the measuring and labor associated with installing the seals in the compressor.
Factors affecting capital cost, operating cost revenue	Depending on the size of the compressor shaft, the capital costs will vary. The larger the shaft, the higher the capital cost. Revenue ranges based on gas price range ($3/Mcf to $7/Mcf).
Other key details	
Reliability in operation	Dry seals are mechanically simpler and have fewer ancillary components, which translates to higher overall reliability and less compressor downtime.
Applicability	All centrifugal compressors with wet seals, operating at a pressure less than 207 bars (3,000 psi) and a temperature less than 149 ^{o}C (300° F).
Technology maturity	*Mature*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IM: Immediate - <12 months. Commercially available.*
Expected future developments (e.g. increase in applicability, reduction in capex, opex if relevant, quantify)	90 percent of all new centrifugal compressors are equipped with dry seals. Dry seals should be the technology of choice for all new compressors. Industry is expected to move towards reducing emissions even further by employing an ejector to recover dry seal emissions. The system would route vapor captured from centrifugal compressor seal oil degassing back to the compressor suction or fuel system.
Experience (number of applications)	90 percent of new centrifugal compressors are equipped with dry seals, as mentioned above.
References for further info	http://epa.gov/gasstar/documents/ll_wetseals.pdf

[159] Replacing Wet Seals with Dry Seals in Centrifugal Compressors, Natural Gas STAR Lessons Learned, P.1.

[160] M2M presentation, http://www.globalmethane.org/documents/events_oilgas_20090914_robinson3.pdf

Feedback from operators and regulators on performance	Industry contacts have reported that seal conversion has significantly reduced operating costs and methane emissions. Industry is even moving towards recovering dry seal leaked emissions.
Limitations	Dry seals limited to operating conditions of 207 bars (3,000 psi) pressure and 148 (300 ^{o}F) temperature.

9. Installing a Wet Seal Degassing Recovery System

Introductory information: (mutually exclusive from Installing a Wet Seal Degassing Recovery System)			
Name of technology/practice	Installing A Wet Seal Degassing Recovery System for Centrifugal Compressors		
Supplier(s)	Unknown – Only reported implementation was part of entire facility construction		
Which fugitive GHG emission source does it target?	Centrifugal compressor venting from wet seal degassing		
Which primary GHG does it target?	Methane (CH_4)		
Brief details on how it works	Wet seals (high pressure oil) on the rotating shafts of centrifugal compressors act as a barrier to the high pressure gas inside the centrifugal compressor. When this oil is stripped of the gas it absorbs, the gas is vented. Operators can install a recovery system that captures this gas and routes it for beneficial use either to a low-pressure fuel line, higher pressure fuel line, or compressor suction.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	N/A	99%	N/A
Key factors affecting this		See below.	
Typical average methane recovery efficiency	99%		
Key factors affecting this	The instances where the recovered gas cannot be injected into a fuel line or compressor suction. Such instances may include system shutdowns for maintenance or changes in fuel quality. Under such circumstances the gas should be routed to a flare.		

Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	VRUs capture many other btu-rich hydrocarbon vapors that would otherwise be vented to the atmosphere. VRUs also eliminate VOC and HAP (e.g., Hexane, Hydrogen Sulfide)[161] emissions.[162] Abatement efficiency for secondary emissions is 99%.
Energy/resource consumption	Natural Gas
Indirect GHG emissions resulting from this	
Costs	
CapEx per unit	*For One Centrifugal Compressor* $31,000 (high pressure seal oil gas separator) $26,000 (low and high quality seal oil vapor gas filters/separators) Total = $57,000 *For Four Centrifugal Compressors* $125,000 (high pressure seal oil gas separator) $42,000 (low and high quality seal oil vapor gas filters/separators) Total = $167,000
OpEx per unit	Negligible
Revenue per well and per unit production	$135,360 - $315,840/year
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	The wet seal degassing recovery system capital cost depends on the size and construction material of the separator and filter vessels. For each centrifugal compressor one seal oil gas separator must be installed for each seal. The seal oil vapor filters subsequently must be sized to handle the volume of gas from all centrifugal compressors connect to the wet seal degassing recovery system.
Factors affecting capital cost, operating cost revenue	The capital costs are directly proportional to the number of centrifugal compressor connected to the wet seal degassing recovery system.
Other key details	
Reliability in operation	Unknown
Applicability	Limited to centrifugal compressors with wet seals located near equipment that can use the recovery gas as fuel.
Technology maturity	*Demonstration*

[161] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

[162] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*MT: Medium Term – 5 – 10 years. Not commercially available. Design/experimental stage and will require further development, research and commercialization.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	
Experience (number of applications)	Unknown, only one documented experience with technology
References for further info	http://epa.gov/gasstar/documents/ll_wetseals.pdf
Feedback from operators and regulators on performance	One Natural Gas Partner has reported success with this technology.
Any disadvantages	Not applicable at all sites.

10. Reduced Emission Completions on Low Pressure Wells

Introductory information (mutually exclusive of Reduced Emission Completion and Reduced Emission Completion on Exploratory Wells)	
Name of technology/practice	Low Pressure Reduced Emission Completions (RECs)
Supplier(s)	Global Suppliers: Weatherford
Which fugitive GHG emission source does it target?	1) Flowback Venting during Hydraulically Fractured Well Completions from Low Pressure Wells 2) Flowback Venting during Hydraulically Fractured Well Workovers from Low Pressure Wells
Which primary GHG does it target?	Methane (CH_4)
Brief details on how it works	RECs capture gas and condensate produced during well completions and well workovers with hydraulic fracturing during the flowback of the fracture fluids. Low pressure wells do not have sufficient pressure to flow through REC equipment and into a gas gathering line. Therefore, completion flowback gas is compressed to high pressures and re-injected into the well bore to maintain the flow of gas through the REC and into the gathering line. In some cases, operators may need to purchase and inject supplementary gas from a nearby pipeline down the well bore to maintain the well flow pressure and ensure the flow of gas through the REC and into the gathering line.[163] During a gas well completion with hydraulic fracturing on a low pressure well, fracture fluid (primarily water and sand) and natural gas are injected into the well and reservoir at high pressure. Subsequently, natural gas from the fractured reservoir and the injected natural gas push the fractured fluid out of the well bore (i.e., flowback). The flowback is a mixture of natural gas, condensate, and saturated fracture fluids and is not suitable for gathering pipelines. Operator's need to remove the majority of the fracture fluids to prepare the well for connection to a gathering pipeline and to recover the injected natural gas. Without a REC, the flowback is typically flown into a pit where the gas is vented and the fracture fluids are collected. To capture the gas, portable equipment (REC) that is specially designed and sized for the initial high rate of water, sand, and gas flowback is brought on site. The objective is to separate the gas from the solids and liquids produced during the high-rate flowback, so that the initially produced gas can be delivered into the sales pipeline. A REC system for low pressure wells will include a sand trap to remove the finer solids present in the production stream, plug catchers that are used to remove any large solids such as drill cuttings that could separate other separation equipment, and a three phase separator is used to remove the free water and condensate from the flowback gas. Two compressors are used to inject pipeline gas or provide suction to the well in order to maintain sufficient flowing pressure for the gas to flow through the REC equipment and into the gathering line. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. The REC and injection compressors are kept at the

[163] Smith, R. (2011) *Using Reduced Emission Completions (RECs) to Minimize Emission During Flow-back of Hydraulically Fractured Gas Wells*. Global Methane Initiative All-Partnership Meeting. https://www.globalmethane.org/documents/events_oilgas_101411_tech_smith.pdf

	well site until the flowback natural gas is the appropriate spec (i.e., low concentration of fracture fluid) to inject into the gathering pipeline without the REC equipment. Depending on the gas gathering system, it may be necessary to dehydrate (remove water from) the produced gas before it enters the sales pipeline.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	90%	90%	N/A
Key factors affecting this	Depends on whether RECs are used in conjunction with flares. Flares would worsen REC CO_2 mitigation.	Depends on whether RECs are used in conjunction with flares. Flares improve REC methane mitigation.	Assumes RECs are not used in conjunction with flares. Flaring natural gas emits N_2O.
Typical average methane recovery	90%		
Key factors affecting this	Gas composition: RECs are designed to tolerate specific volumes of sand and liquids. The composition of the natural gas exiting the wellhead will determine if an REC is feasible. Also, the economic case for an REC is heavily driven by the recovery of valuable NGLs. NGL-rich natural gas is more likely to be captured. Access to Gas Gathering Pipeline: RECs require a gathering pipeline to collect and distribute the recovered gas either for sale or for processing. For some low pressure wells, a nearby gas gathering system is necessary to purchase supplementary gas to inject into the well bore.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[164] (e.g., Hexane, Hydrogen Sulfide) Reduced Flaring Natural Gas Liquids (propane, butane, pentane, hexane, heptane). This is an additional revenue stream. Abatement efficiency for secondary emissions is 90% (assumed no flare is used in conjunction with the low pressure well REC)		
Energy/resource consumption	Low pressure wells require gas compression to maintain sufficient flowing pressure for the gas to flow through the REC equipment and into the gathering line. Two compressors will be used to compress purchases and/or flowback gas for injection into the well bore. These compressors will likely be reciprocating compressor driven by diesel or natural gas engines. Diesel engines will require additional diesel fuel to be brought to the well site. Natural gas engines will likely used purchased gas or recovered gas for fuel reducing the effectiveness of the REC.		
Indirect GHG emissions resulting from this	The two compressors required to implement a REC on low pressure wells will generate indirect CH_4, CO_2, N_2O, NOx, CO, SO_x, and other combustion related emissions associated with compressor engines. Fugitive emissions associated with reciprocating compressors will also be emitted.		

[164] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

Costs	
CapEx per well (2008 U.S. dollars):	Purchase Case: REC Equipment: $575,846 First Compressor: $1,100,000 (includes 700 HP engine and two scrubbers) Second Compressor: $ 400,000 (includes 200 HP engine and two scrubbers)[165] Total Cost: $2,075,846
OpEx per well (2008 U.S. dollars):	Purchase Case: - REC Transportation and Set Up Cost: $691 per completion - REC Labor Costs: $1,244 per completion[166] - Fuel Use: 4,000 – 120,000 m^3 per completion (assumed 20 hours of use per day) * Price of Natural Gas [167] *Well flowback can last from 1 to 30 days. - Compressor Maintenance: $3,000 per completion (assumed $10 per horsepower per month) [168] - Buying Gas to Inject into Well: 21,000 m^3/completion * Price of Natural Gas Rent Case: - REC Transportation and Set Up Cost: $691 per completion - REC Equipment Rental and Labor Cost: $806 - $7,486 per day[169] *Well flowback can last from 1 to 30 days. - First Compressor Rental and Labor Cost: $7,000 per month[170] - Second Compressor Rental and Labor Cost: $4,000 per month[171] - Fuel Use: 4,000 – 120,000 m^3 per completion * Price of Natural Gas (assumed 20 hours of use per day) [172] *Well flowback can last from 1 to 30 days. - Buying Gas to Inject into Well: 21,000 m^3/completion * Price of Natural Gas
Revenue per well and per unit production	$405,000 - $945,000 per year (with purchased equipment). Assuming 25 completions per year. $16,200 - $37,800 per completion (with rented equipment)[173]

[165] Turton, et al. "7.3.2 Module Costing Technique." Analysis, Synthesis, and Design of Chemical Processes. 3rd edition. Pearson Education, Inc., pages 192 to 209. 2008

[166] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

[167] EPA (2006). "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance," *Lessons Learned*. pg. 4. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

[168] EPA (2006). "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance," *Lessons Learned*. pg. 5. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

[169] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

[170] Maloney, T. (2012) "Stranded Gas/Liquids Capture and Transport". *North Dakota Pipeline Association Webinar*. Slide 9. Accessed online on July 9, 2013 at ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf

[171] Maloney, T. (2012) "Stranded Gas/Liquids Capture and Transport". *North Dakota Pipeline Association Webinar*. Slide 9. Accessed online on July 9, 2013 at ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf

[172] EPA (2006). "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance," *Lessons Learned*. pg. 4. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Assumed capture of 3,800 m^3 (135,000 Mcf) per year (with purchased equipment), assuming 25 completions per year. Assumed capture of 150 m^3 (5,400 Mcf) per completion (with rented equipment). For revenue, gas price ranged from $3 to $7 per Mcf. Assumed low pressure wells produce half the flowback gas per completion than higher pressure wells that can utilize an REC without supplemental compression.
Factors affecting capital cost, operating cost, revenue	Availability of REC equipment, availability of compressors, availability of pipeline, pressure of produced gas, price of gas.
Other key details	
Reliability in operation	There are multiple factors that determine REC reliability. Each REC application is subject to: • The producing reservoir which affects flowback pressure, gas composition, duration of flowback, and steady or erratic flow behavior. • The fracture fluid pumped down the well which includes: total volume received during flowback, concentration of water and sand in flowback. RECs are designed to handle a maximum flow rate of solids and liquids.
Applicability	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 that management practices in the EU may differ from those in the U.S. For example, in the U.S. many operators flow hydraulic fracture fluid into open-lined pits during a well completion. Operators in the EU may choose, for example, to flow hydraulic fracture fluid into temporary tanks.
Technology maturity	*Commercially available but low market penetration*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IN: Intermediate – 1 – 5 years. Commercially available, but low market penetration.*
Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	As REC equipment becomes more widely available and experience with implementing them improves, the associated capital and operating costs will come down. This will increase the profitability of using REC technology.
Experience (number of applications)	The number of applications is unknown, however, U.S. operators have stated anecdotally that this technology has been implemented.
References for further info	http://epa.gov/gasstar/documents/reduced_emissions_completions.pdf ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf
Feedback from operators and regulators on performance	Little information has been provided by operators on REC performance for hydraulically fractured low pressure well completions.

[173] Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, U.S. EPA Lessons Learned, P.1.

Limitations	Below is a list of limitations for implementing RECs: • Proximity to existing gas gathering infrastructure. Exploratory wells are typically not drilled next to existing infrastructure. Lack of existing gas gathering infrastructure may make REC applications too costly or not feasible. • The composition of the recovered natural gas may not be suitable for injection into the gathering system. High concentrations of CO_2 or H_2S in the gas stream may prohibit operators from recovering the gas.

11. Reduced Emission Completions on Exploratory Wells

Introductory information (mutually exclusive of Reduced Emission Completion and Reduced Emission Completion on Low Pressure Wells)	
Name of technology/practice	Reduced Emission Completions (RECs) on Exploratory Wells
Supplier(s)	Global Suppliers: BX Energy (only USA)
Which fugitive GHG emission source does it target?	1) Flowback Venting during Hydraulically Fractured Well Completions from Exploratory Wells
Which primary GHG does it target?	Methane (CH_4)
Brief details on how it works	RECs capture gas and condensate produced during well completions with hydraulic fracturing during the flowback of the fracture fluids. Exploratory wells are drilled in new areas or areas with unknown potential where reservoir characteristics such as flow rate, lifetime, composition, and temperature must be determine before scaling up production. Exploratory wells typically do not have access to a gas gathering infrastructure and therefore cannot implement an REC without an alternate method to transport the produced gas. Therefore in order to perform a REC on an exploratory well, the captured completion flowback gas must be captured, treated, dehydrated, compressed, and finally loaded onto tube trailers for delivery to the nearest gathering system or processing facility. Tube trailers are mobile racks that can be loaded onto trucks consisting of several stainless steel tubes designed to hold high pressure (~3500 psig) natural gas. During a gas well completion with hydraulic fracturing on an exploratory well, fracture fluid (primarily water and sand) is injected into the well and reservoir at high pressure. Subsequently, natural gas from the fractured reservoir pushes the fractured fluid out of the well bore (i.e., flowback). The flowback is a mixture of natural gas, condensate, and saturated fracture fluids and is not suitable for tube trailers. Operator's need to remove the majority of the fracture fluids and natural gas liquids to prepare natural gas for tube trailer loading. Without a REC, the flowback is typically flown into a pit where the gas is vented and the fracture fluids are collected. To capture the gas, portable equipment (REC) that is specially designed and sized for the initial high rate of water, sand, and gas flowback is brought on site. The objective of the REC is to separate the gas from the solids and liquids produced during the high-rate flowback, so that the initially produced gas can be compressed and loaded onto tube trailers for delivery. A REC system will include a sand trap to remove the finer solids present in the production stream, plug catchers that are used to remove any large solids such as drill cuttings that could separate other separation equipment, and a three phase separator is used to remove

	the free water and condensate from the flowback gas. In addition to the REC system exploratory wells require a heater-treater or line heater to heat the gas to remove natural gas liquids, two compressors to raise the pressure of the gas from around 35 psig to 3,500 psig, and hoses to load the natural gas on to tube trailers, which are transported to the nearest gathering line or processing facility. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. The REC, heater, compressors, and tube trailers are kept at the well site until the exploratory well is connected to a gathering line or shut-in.		
Performance	CO_2	CH_4	N_2O
Typical abatement efficiency for key GHGs (primary abatement metrics), %	90%	90%	N/A
Key factors affecting this	Depends on whether RECs are used in conjunction with flares. Flares would worsen REC CO_2 mitigation. Erratic flowback may limit the ability for consistent compression and subsequent loading on to tube trailers for capture.	Depends on whether RECs are used in conjunction with flares. Flares improve REC methane mitigation. Erratic flowback may limit the ability for consistent compression and subsequent loading on to tube trailers for capture.	Assumes RECs are not used in conjunction with flares. Flaring natural gas emits N_2O.
Typical average methane recovery	90%		
Key factors affecting this	Gas composition: RECs are designed to tolerate specific volumes of sand and liquids. The composition of the natural gas exiting the wellhead will determine if an REC is feasible. Also, the economic case for an REC is heavily driven by the recovery of valuable NGLs. NGL-rich natural gas is more likely to be captured.		
Secondary abatement metrics (while GHGs are the focus there may be co-benefits in terms of AQ resulting from abatement of NOx, SOx)	Volatile Organic Compounds (VOCs) Hazardous Air Pollutants (HAPs)[174] (e.g., Hexane, Hydrogen Sulfide) Reduced Flaring Natural Gas Liquids (propane, butane, pentane, hexane, heptane). This is an additional revenue stream. Abatement efficiency for secondary emissions is 90% (assumed no flare is used in conjunction with the exploratory well REC)		
Energy/resource consumption	Exploratory wells require gas treatment and compression to load the gas on to tube trailers for transport to the nearest gathering line or processing facility. One heater-treater or line heater will be used to remove natural gas liquids from the captured flowback gas. This heater will likely use natural gas fueled burners. Two compressors will be used to compress the flowback gas		

[174] As defined by the U.S. EPA: <www.epa.gov/ttnatw01/187polls.html>

	for loading on to tube trailers. These compressors will likely be reciprocating compressor driven by diesel or natural gas engines. Diesel engines will require additional diesel fuel to be brought to the well site. Natural gas engines will likely use purchased gas or recovered gas for fuel reducing the effectiveness of the REC. Finally, the trucks used to transport the tube trailers to the nearest gathering line or processing facility will consume diesel fuel.
Indirect GHG emissions resulting from this	The two compressors, heater burner, and truck engines required to implement a REC on exploratory wells will generate indirect CH_4, CO_2, N_2O, NOx, CO, SO_x, and other combustion related emissions associated with burners and engines. Fugitive emissions associated with reciprocating compressors will also be emitted.
Costs	
CapEx per well (2008 U.S. dollars):	Purchase Case: REC Equipment: $575,846 Compression and Dehydration Skids: $1,500,000 (Assumes peak flow rate of 78,000 m^3/day)[175] Total Cost: $2,075,846
OpEx per well (2008 U.S. dollars):	Purchase Case: - REC Transportation and Set Up Cost: $691 per completion - REC Labor Costs: $1,244 per completion[176] - Compressor Fuel Use: 4,000 – 120,000 m^3 per completion (assumed 20 hours of use per day) * Price of Natural Gas [177] *Well flowback can last from 1 to 30 days. - Operator and Maintenance: $69,400 per year - Tube Trailer Leasing: $6,300 per month (assuming two tube trailers) - Hose/Connector Sets: $500 per month - Discharge Skids at Delivery Point: $1,000 per month - Transportation Labor and Fuel Costs: $7,200 - $216,000 (assuming 3 hours per load, $120 per hour, and 20 loads per day) *Well flowback can last from 1 to 30 days. [178] Rent Case: - REC Transportation and Set Up Cost: $691 per completion - REC Equipment Rental and Labor Cost: $806 - $7,486 per day[179] *Well flowback can last from 1 to 30 days. - Compressor and Dehydrator Skid Rental: $11,000 per month[180]

[175] Maloney, T. (2010) : "Wellhead Gas Capture Via CNG Technologies" *Oil and Gas Research Program*. http://www.nd.gov/ndic/ogrp/meet1008/propg-022-c.pdf

[176] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

[177] EPA (2006). "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance," *Lessons Learned*. pg. 4. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

[178] Maloney, T. (2012) "Stranded Gas/Liquids Capture and Transport". *North Dakota Pipeline Association Webinar*. Slide 9. Accessed online on July 9, 2013 at ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf

[179] Background Supplemental Technical Support Document for the Final New Source Performance Standards, http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

	- Compressor Fuel Use: 4,000 – 120,000 m^3 per completion * Price of Natural Gas (assumed 20 hours of use per day) [181] *Well flowback can last from 1 to 30 days. - Tube Trailer Rental: $6,300 per month (assuming two tube trailers) - Hose/Connector Sets: $500 per month - Discharge Skids at Delivery Point: $1,000 per month - Transportation Labor and Fuel Costs: $7,200 - $216,000 (assuming 3 hours per load, $120 per hour, and 20 loads per day) *Well flowback can last from 1 to 30 days.
Revenue per well and per unit production	$810,000 - $1,890,000 per year (with purchased equipment). Assuming 25 completions per year. $32,400 - $75,600 per completion (with rented equipment)[182]
Details of application that the cost data refers to (size, type, production, geology, gas price, etc.)	Assumed capture of 7,600 m^3 (270,000 Mcf) per year (with purchased equipment), assuming 25 completions per year. Assumed capture of 300 m^3 (10,800 Mcf) per completion (with rented equipment). For revenue, gas price ranged from $3 to $7 per Mcf.
Factors affecting capital cost, operating cost, revenue	Availability of REC equipment, availability of pipeline, pressure of produced gas, price of gas.
Other key details	
Reliability in operation	There are multiple factors that determine REC reliability. Each REC application is subject to: • The producing reservoir which affects flowback pressure, gas composition, duration of flowback, and steady or erratic flow behavior. • The fracture fluid pumped down the well which includes: total volume received during flowback, concentration of water and sand in flowback. RECs are designed to handle a maximum flow rate of solids and liquids.
Applicability	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 that management practices in the EU may differ from those in the U.S. For example, in the U.S. many operators flow hydraulic fracture fluid into open-lined pits during a well completion. Operators in the EU may choose, for example, to flow hydraulic fracture fluid into temporary tanks.
Technology maturity	*Demonstration on hydraulically fractured oil wells producing associated gas – no known implementation for exploratory gas wells*
Technology uptake time (estimate of implementation time based on the maturity of the technology, requirements for retro-fit, ship newbuilds, research or design)	*IN: Intermediate – 1 – 5 years. Low market penetration.*

[180] Maloney, T. (2012) "Stranded Gas/Liquids Capture and Transport". *North Dakota Pipeline Association Webinar*. Slide 9. Accessed online on July 9, 2013 at ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf

[181] EPA (2006). "Using Pipeline Pump-Down Techniques To Lower Gas Line Pressure Before Maintenance," *Lessons Learned*. pg. 4. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf

[182] Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, U.S. EPA Lessons Learned, P.1.

Expected future developments (e.g. increase in applicability, reduction in CapEx, OpEx if relevant, quantify)	This technology requires significant capital and operational expenditures to transport natural gas to market from an exploratory well. The price of natural gas and the availability of tube trailer solutions for remotely located gas wells will determine the economics for this technology going forward. In addition, exploratory wells are not proven to yield significant gas production, therefore there is higher risk that the well will not yield as much salable product.
Experience (number of applications)	The number of applications is unknown; however, a United States service provider has presented that this technology has been implemented for hydraulically fractured oil wells producing associated gas. [183]
References for further info	http://epa.gov/gasstar/documents/reduced_emissions_completions.pdf ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf
Feedback from operators and regulators on performance	Little information has been provided by operators on REC performance and transporting wellhead gas using tube trailers for hydraulically fractured exploratory well completions.
Limitations	Below is a list of limitations for implementing RECs: • The composition of the recovered natural gas may not be suitable for storage and transportation in a tube trailer. High concentrations of CO_2 or H_2S in the gas stream may prohibit operators from recovering the gas. • Hauling tube trailers are subject to local road/transportation laws. EU member states may have restrictions for weight or flammable materials on roadways and bridges.

[183] Maloney, T. (2012) "Stranded Gas/Liquids Capture and Transport". *North Dakota Pipeline Association Webinar*. Slide 9. Accessed online on July 9, 2013 at ndpipelines.files.wordpress.com/2012/11/ndpa-webinar-slides-12-18-2012.pdf

Appendix C – Selected Member State Survey Responses

1. Denmark (consultation with Katja Scharmann, Danish Energy Agency)

Context

So far, two licenses for shale gas exploitation have been awarded in Denmark. They are still in exploration phase and no exploitation has occurred so far. In mid-2012 a moratorium of two years was established preventing the award of new licenses until more is known about the environmental impacts of shale gas exploitation. At the moment there are no plans to develop new legislation regarding unconventional gas. However, there is ongoing discussion around the issue and more is expected as a small political party intends to bring the complete ban of shale gas exploitation on the agenda in April 2013. In the case of offshore exploitation, the Danish Energy Agency is the competent authority. In the case of onshore exploitation, the Danish Energy Agency is competent for subsoil activities while the Danish Environmental Agency and the municipalities are competent for above ground activities (e.g. land use, GHG emissions). The two most relevant legislations for shale gas exploration and exploitation are **The Subsoil Act** and the **EIA legislation**.

Hydrocarbon legislation – The Subsoil Act	
Name of regulation / measure	There are no specific regulations for shale gas exploration and exploitation in Denmark. The Subsoil Act covers all types of installations: unconventional and conventional, onshore and offshore.
Status	Legislation in place
Type	Mandatory for all exploration and exploitation projects and for all installations (onshore)
Relevant authority responsible	Danish Energy Agency
Details	
Aim / goals	Monitor hydrocarbon exploitations
Which fugitive GHG emission sources are targeted?	This regulation requires all hydrocarbon installations to have closed system to prevent **venting**, which is forbidden in Denmark. The obligation is included in the drilling permit and as a condition in the approval of the development plan. The legislation also stets strong restriction to **flaring**. Maximum amount of flaring are sets based on the production target of the installations and on the best available techniques. Flaring activities are monitored on a daily and monthly basis and enquiries are led if the allowed amounts are trespasses without reasons (e.g. security reasons associated with specific stages of the exploitation process).
Specific provisions for minimising fugitive GHG emissions (directly or indirectly)	Specific guidelines or technical requirements may exist. Check with the Danish Environmental Agency.
Provisions for monitoring, reporting & verification of fugitive GHG emissions	The Danish Energy Agency monitors the amount of flaring on a daily and monthly basis. All exploitations have to report their amount of flaring as part of their daily and monthly production report.
Compliance enforcement / sanctions	If the requirements in terms of venting and flaring are not followed the production may be stopped. This is decided on a case by case basis.

Other environmental control provisions	The Environmental Agency has developed different legislation for water protection. No specific regulation exists regarding the prevention/mitigation of possible earthquakes associated with fracking.

EIA Legislation	
Name of regulation / measure	EIA Regulation: There is no specific EIA regulation for Shale gas. Potential shale gas projects have to follow the same rules as conventional exploitation projects. - Executive order No. 632 of June 11, 2012 defines the rules for the EIA for offshore exploration and production of hydrocarbons projects; - Similar EIA requirements exist for onshore hydrocarbon installations (defined by the Environmental Agency). Since mid-2012, full EIA have to be developed for all onshore shale gas wells requiring hydraulic fracturing. This is not the case for offshore shale wells.
Status	Legislation in place
Type	Mandatory for all exploitation projects
Relevant authority responsible	In the case of offshore exploitation, the Danish Energy Agency is the competent authority. In the case of onshore exploitation, the Danish Energy Agency is competent for subsoil activities while the Danish Environmental Agency and the municipalities are competent for above ground activities (e.g. land use, GHG emissions).
Details	
Aim / goals	/
Which fugitive GHG emission sources are targeted?	The EIA covers all GHG emissions associated with hydrocarbons exploitation. If the amount of GHG emissions is estimated too high, the design of the project has to be modified.
Specific provisions for minimising fugitive GHG emissions (directly or indirectly)	/
Provisions for monitoring, reporting & verification of fugitive GHG emissions	/
Compliance enforcement / sanctions	/
Other environmental control provisions	/
Other	
Linkages to other policies	/

2. United Kingdom (consultation with John Arnott, Oil and Gas Licensing, UK Department for Energy and Climate Change, DECC)

Context

DECC is the department in charge of issuing licences to exploit hydrocarbons through Petroleum Exploration and Development Licences (PEDL) rounds. This licencing framework is the only policy framework allowing DECC to control methane emissions associated with oil and gas (conventional and unconventional) exploitation – see table below. This control role is based on the "natural resources preservation" principle. The licencing process does not consider other GHG emissions. John Arnott does not expect the development of completely new regulation regarding shale gas exploration and exploitation. However new technical guidance documents have been or are expected to be published by the UK Environment Agencies:

- Scottish Environmental Protection Agency (EPA) (2013): Regulatory guidance – CBM and shale gas;
- UK Environment Agency (EA): Announcement of the publication of new technical guidance for the planning of unconventional gas exploitation
- UK Onshore Operators Group (UKOOP): UK Onshore Shale Gas Well Guidelines: Exploration and appraisal phase, February 2013[184]

The Environmental Agency is the regulator for shale gas operations in England[185]. They published in December 2012 a Guidance Note covering their regulation of the exploration of shale gas using deep drilling and high volume hydraulic fracking[186]. The EA is currently discussing with the other British governmental bodies involved in the legal framework regulating shale gas operations and final regulatory guidance should be published in May 2013. This will be followed-up by technical guidance in July or August 2013. These guidance documents will only address shale gas exploration and not the economic exploitation. They will also not cover other form of unconventional gas (such as CBM). As presented below the principal Regulation managed by the EA concerning shale gas is the Environmental Permitting Regulation 2010 which transposed many elements of the EU Mining Waste Directive (see description below).

An important point to discuss concerns the adaptation of the regulatory framework that will be needed in the perspective of the commercialisation of shale gas. Under the current Mining Waste Directive, fugitive methane from shale gas exploration is considered as waste as it cannot be commercialised. In accordance with the Directive it has to be minimised as much as technically possible and the remaining methane has to be flared. However when wells will be drilled with commercialisation as goal, fugitive methane will not be considered as waste anymore. It will be considered as a commercial product and flaring will not be allowed under the existing regulatory framework. Therefore a new or adapted regulatory framework covering commercial exploitation of shale gas will be needed.

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[184] Available online here: http://www.ukoog.org.uk/elements/pdfs/ShaleGasWellGuidelines.pdf

[185] On 1 April 2013 a new single body for Wales will bring together the functions of the Countryside Council for Wales, Environment Agency Wales and Forestry Commission Wales. This single body will take on accountability for services currently delivered by us, both in or to Wales.

[186] Document available at: http://www.vtt.fi/sites/green_vtt/green_transport.jsp?lang=en

DECC – Petroleum Exploration and Development Licences	
Name of regulation / measure	There are no specific regulations on shale gas in the UK. DECC controls methane emissions associated with flaring and venting activities associated with oil and gas (conventional and unconventional) exploitation. Their approach is based on policy statements and not on specific legislation.
Status	Policy in place
Type	Mandatory for all oil and gas installations
Relevant authority responsible	DECC
Details	
Aim / goals	DECC's approach is based on the following principle: - Venting of methane has to be reduced to the technical minimum; - Flaring of methane has to be reduced to the economic minimum. DECC recognises that in some cases flaring is the most economic option.
Which fugitive GHG emission sources are targeted?	This framework covers only venting and flaring of methane emissions and does not address other GHG emissions.
Specific provisions for minimising fugitive GHG emissions (directly or indirectly)	Specific requirement for the definition of the maximum amount of venting and flaring allowed: - Venting: Technical minimum. A higher level of emissions than the minimum technical level is unlikely to be awarded. - Flaring: The level of flaring allowed is defined on a case by case basis. (Based among others on: safety measures, technical specificities, etc.)
Provisions for monitoring, reporting & verification of fugitive GHG emissions	Installations which receive flaring allowances have to submit a "flaring report" every month to DECC. This report has to mention the exact level of flaring that occurred during the last month. If the allocated level is exceeded, explanations have to be provided. These "flaring" report are distinct from the production report.
Compliance enforcement / sanctions	The possibility to start coercive action exists under the licencing framework. However, so far no coercive actions have been engaged in the cases of installations exceeding methane venting and/or flaring. When companies do trespass their allocated amounts of flaring and venting they have to provide explanations. If this would occur too often, the possibility to develop a stricter control regime would be considered.
Other environmental control provisions	/
Other	

Linkages to other policies	This is the only policy measure developed by DECC regarding the control of methane emissions associated with shale gas exploration and exploitation. There exists other initiatives at other levels: - The Environmental Agency is responsible for the monitoring of GHG emissions – Consult them regarding the evolution of the regulatory framework; - The planning authorities (Mineral planning at local level – county council) can impose control on truck movement associated with economic activities. This might be a way to control the indirect GHG emissions associated with shale gas exploration and exploitation.

Environmental Permitting Regulations 2010	
Status - Date	- In place - Applied at point of permit determination
Type	- Mandatory - Who does it address? – the operator - Size of the projects covered? – any shale gas exploration
Relevant authority responsible	- Environment Agency (England)
Details	
Aim / goals	- To control the release of gases, which are considered as waste under the Mining Waste Directive, and in doing so reduce the impact on the environment and public health. Based on the Mining Waste Directive, the rationale is to minimize the fugitive gas as much as technically feasible. Operators are encouraged to use the fugitive gases on the site or to burn it to reduce its harmful environmental impact. During the exploration phase, operators cannot commercialize the gas they extract.
Which fugitive GHG emission sources are targeted?	- What exactly does it cover? It is targeted at any emissions of waste gases released during exploratory drilling and any significant hydrocarbons from the management of flowback waters
Specific provisions for minimising fugitive GHG emissions (directly or indirectly)	- Technical requirement (types of pollutants? Technologies? - The capture, separation and treatment of all gaseous waste emissions. - While no shale gas specific BAT Reference documents are available the flare stack will be required to meet the standards set out in cww_bref_0203 BAT in common waste water and waste gas treatment/management systems in the chemicals sector. - EPR sector-specific and IPPC sector guidance notes include guidance on monitoring requirements and methods based on information derived from the relevant BREFs - http://www.environment-agency.gov.uk/business/regulation/31831.aspx - At the separator there is a requirement to monitor for oxides

	of carbon, methane and hydrogen sulphide.
Provisions for monitoring, reporting & verification of fugitive GHG emissions	- How often does MRV occur? - Operator Monitoring of the flare when in operation will be continuous. Monitoring requirements and any limits will be reviewed after six months. - Which techniques are used? - Details are currently being evaluated and will be with agreement of the regulator.
Compliance enforcement / sanctions	- Extensive range of options available
Other environmental control provisions	- Abstraction of surface and groundwaters along with ground water protection regulated by the Environment Agency. Proposals to drill or extend any well must be submitted to the Environment Agency so the impact on water resources can be assessed. BGS are currently undertaking a baseline review of methane in groundwaters in the UK. - There is also an obligation to monitor for hydrogen sulphide by the Health & Safety Executive to protect operator safety

Northern Ireland (consultation with Bruce Harper, Air & Environmental Quality Unit, Department of Energy (DoE) Environmental Policy Division)

There are currently no specific regulations in place in Northern Ireland to control the GHG emissions associated with the exploration and exploitation of shale gas. The DoE of Northern Ireland has identified different options to regulate the environmental impacts of shale gas exploration and exploitation. These options have been submitted to the Minister of Environment but no decisions have been taken so far regarding which option will be selected. The DoE and the Ministry of Environment are waiting for the publication of two reports on the environmental impact of shale gas exploitation before taking further decisions: a Defra report and a report commissioned by the Irish Environmental Protection Agency. Meanwhile the DOENI has identified four preliminary options to regulate in this area:

- **Option 1:** Use the existing powers in the DETI consent regime to control flaring and prevent gas losses. DETI grant the petroleum licences based on the **Hydrocarbons Licencing Directive Regulations (Northern Ireland) 2010**. This Regulation applies to the exploitation of all types of hydrocarbons and defines rules to control venting and flaring activities. It requires installations to minimise their amount of venting ad flaring to the technical minimum. The objective of this framework is to maximise the exploitation of hydrocarbons. It is not based on environmental concerns.

- **Option 2:** Use the **Planning (Management of Waste from Extractive Industries) Regulations (Northern Ireland) 2010**. This regulation transposes the Mining Waste Directive to regulate air emissions. It requires the extractive industry to use best practices available to minimise waste. These are enforced by the Department of the Environment Planning Service as part of the Planning Permission and require the use of Best Available Techniques (BAT) but have heretofore only been used for conventional mining.

- **Option 3:** Amend the **Pollution Prevention and Control Regulations (Northern Ireland) 2003** to regulate above ground processing or handling activities. These regulations transpose the Integrated Pollution Prevention and Control (IPPC) Directive. Currently on the refining of Natural Gas is covered by these regulations. The regulation requires installations to use best practices available to minimise their pollutions.

- **Option 4:** Use the existing **Health and Safety Legislation** enforced by HSE NI to control emissions from fracking activities:

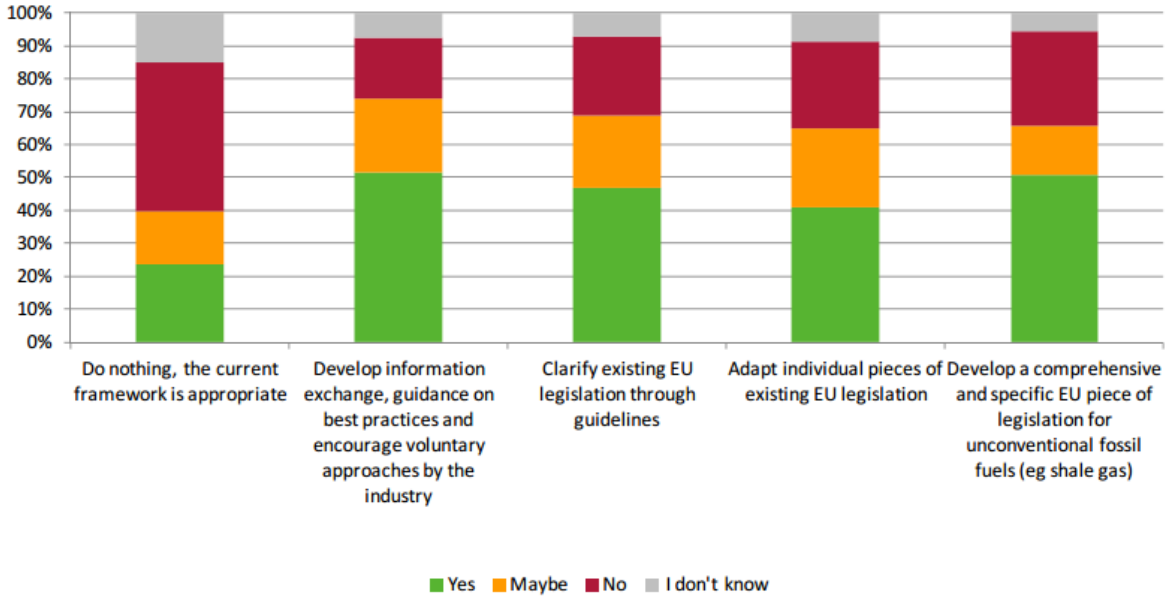
  AEA (2012) report findings: The Offshore Installation and Wells (Design & Construction etc.) Regulations (Northern Ireland) 1996 are applicable to all wells drilled with a view to the extraction of petroleum regardless of whether they are onshore or offshore. These regulations are primarily concerned 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).

One of the DOENI's main concerns regarding these different options concerns the lack of available best practices in the area of shale gas exploration and exploitation. This could strongly jeopardise the efficiency of Option 2 and 3 if they were used.

Appendix D – Results from DG ENV public consultation "Unconventional fossil fuels (e.g. shale gas) in Europe"

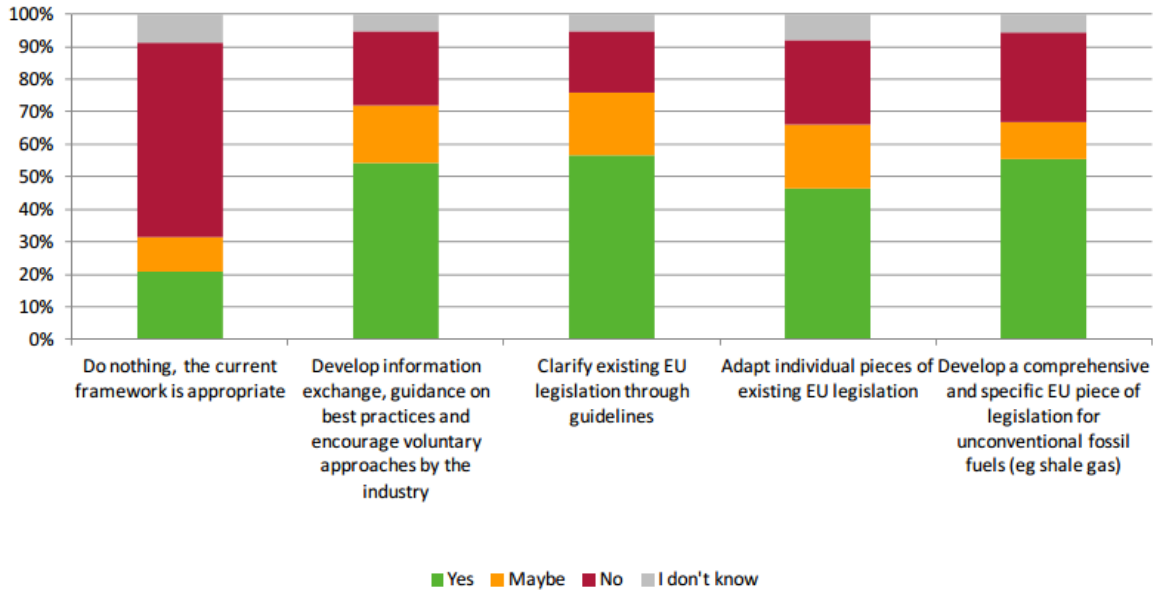
DG ENV launched a public consultation on unconventional fossil fuels on 20 December 2012 and closed it on 23 March 2013. There were 22,875 respondents in total from citizens, organisations and authorities across the EU. The final results have not yet been published. However preliminary results were presented at the stakeholder workshop on June 7th in Brussels.[187]

Figure 3 Answers from individual respondents on policy options to address the identified challenges and risks at EU level



[187] Presentation from DG ENV pubic consultation stakeholder workshop 7th June: http://ec.europa.eu/environment/integration/energy/pdf/Presentation_07062013.pdf

Figure 4 Answers from all organisations on policy options to address the identified challenges and risks at EU level



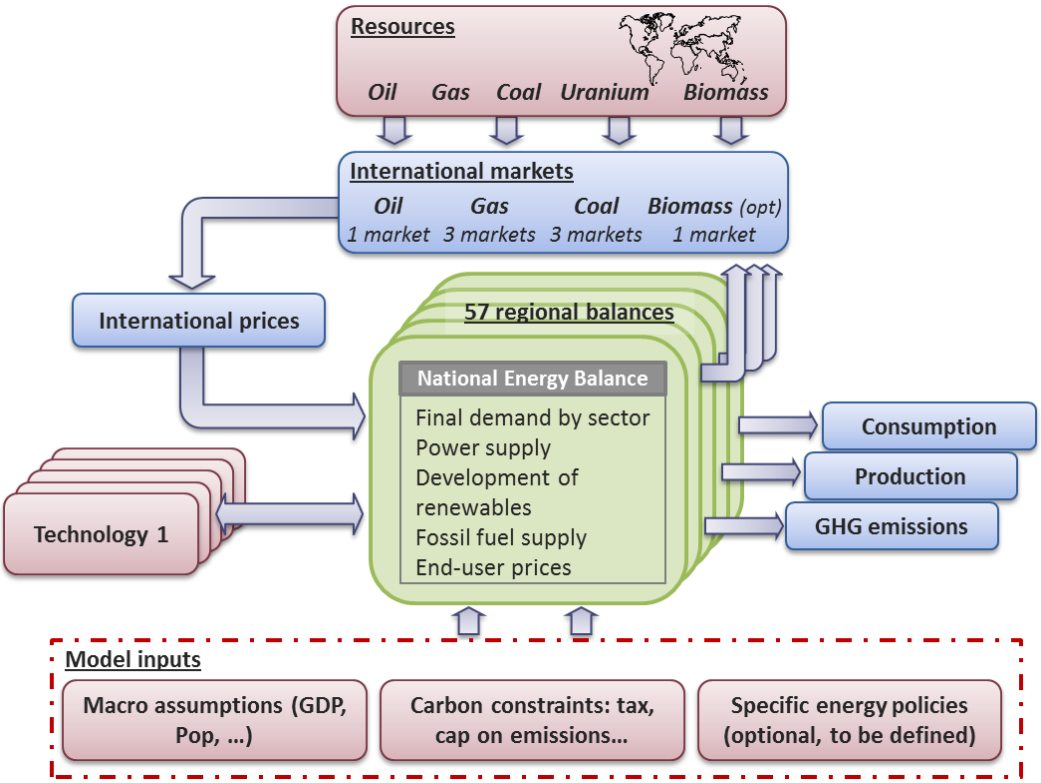
Appendix E – Overview of the POLES Model

1. Overview of the POLES model

Enerdata offers the world recognized POLES model to provide quantitative, scenario-based, empirical and objective analyses. As the POLES model is used by many members of the energy sector (private companies, governments, European Commission), it is very well adapted to forecast the effects of different energy-related engagements (GHG emissions limitations, promotion of renewables and energy efficiency, energy security issues…). In addition, with its global coverage and the endogenous calculation of demand, supply and prices of numerous energies including oil, gas, and coal, the POLES model is very relevant to capture all of the impacts of energy policies and climate change measures and to ensure that all the forecasts are coherent within the global environment.

POLES is a world energy-economy simulation model of the energy sector, with complete modelling from upstream production through to final user demand. The POLES model uses a dynamic partial equilibrium framework, specifically designed for the energy sector but also including other GHG emitting activities (e.g., the six GHG's of the "Kyoto basket"). The simulation process uses dynamic year-by-year recursive modelling, with endogenous international energy prices and lagged adjustments of supply and demand by world region, which allows for describing full development pathways to 2050.

Figure 5



The use of the POLES model combines a high degree of detail for key components of the energy system and a strong economic consistency, as all changes in these key components are influenced by relative price changes at the sectoral level.

The model provides technological change through dynamic cumulative processes such as the incorporation of Two Factor Learning Curves, which combine the impacts of “learning by doing” and “learning by searching” on technologies’ development. As price induced diffusion mechanisms (such as feed-in tariffs) can also be included in the simulations, the model allows for consideration of key drivers to future development of new energy technologies.

One key aspect of the analysis of energy technology development with the POLES model is indeed that it relies on a framework of permanent inter-technology competition, with dynamically changing attributes for each technology. In parallel, the expected cost and performance data for each key technology are gathered and examined in the TECHPOL database that is developed at the EDDEN laboratory of the Grenoble Université Pierre-Mendès-France for any modelling and policy-making purpose.

Key Features

- Long-term (2030, and possibility to go beyond) simulation of world energy scenarios/projections and international energy markets.
- World energy supply scenarios by main producing country/region with consideration of reserve development and resource constraints (80 producing countries/regions).
- Outlook for energy prices at international, national and sectoral level.
- Disaggregation into 25 energy demand sectors, with over 40 technologies (power generation, buildings, transport).
- Detailed national/regional energy balances, integrating final energy demand, new and renewable energy technologies diffusion, electricity, hydrogen and Carbon Capture and Sequestration systems, fossil fuel supply, and uranium (57 consuming countries/regions).
- Full power generation system (and feedback effect on other energies).
- Impacts of energy prices and tax policies on regional energy systems. National greenhouse gas emissions and abatement strategies.
- Costs of national and international GHG abatement scenarios with different regional targets/endowments and flexibility systems.
- CO2 emission Marginal Abatement Cost curves and emission trading system analyses by region and/or sector, under different market configurations and trading rules
- Technology diffusion under conditions of sectoral demand and inter-technology competition based on relative costs and merit orders.
- Endogenous developments in energy technology, with impacts of public and private investment in R&D and cumulative experience with “learning by doing”. Induced technological change of climate policies.
- Data are derived from scenarios simulated on the POLES model, using up-to-date data up to 2011, and GDP and population forecasts from CEPII and UNPD.
- Figures on energy and GHG emissions encompass the energy sector (fossil fuel combustion and industrial processes), but not LULUCF or waste.

GHG policies in POLES can take several forms, such as:

- carbon price (ETS) / carbon value;
- feed-in-tariffs or subsidies;

- changing the competition for new electricity generating capacities to reflect a preference for low-emitting technologies/fuels (as in a renewable portfolio standard or specific political choices); and
- more optimistic assumptions on technological learning rates to reduce production costs for low-emitting technologies;
- increase in final energy efficiency measures though technological innovation, price-induced mechanisms (e.g. pricing of end-user emissions), etc.

Additional information regarding the assumptions and workings of the POLES model can be found at http://ipts.jrc.ec.europa.eu/activities/energy-and-transport/documents/POLESdescription.pdf.

Recent model updates

During 2012, a major update in data and modelling of the oil and gas production in POLES took place to better reflect the current and foreseen state of conventional and unconventional resources. Types of data sources include official government and industry assessments and forecasts.

Data and modelling were evaluated for relevance and comprehensiveness regarding unconventional liquid and gaseous resources, production costs, and energy inputs, covering liquid fuels:

- Oil: conventional (conventional petroleum, tight and shale oil), non-conventional (Bitumen (oil sands), extra heavy oil, oil shale (kerogen)) and environmentally sensitive (Deepwater (>500 m depth), Artic (as defined by the USGS))
- Gas: conventional (conventional gas, tight gas[188]), non-conventional (shale gas)[189] and environmentally sensitive (e.g., deepwater[190] and arctic)

GHG emissions

CO2 EMISSIONS

CO_2 emissions are calculated according to the fossil fuel consumption at the level of:

- Transformation sectors (electricity and hydrogen generation and other energy sector)
- Final demand of energy
- International bunkers

[188] Tight gas is considered a conventional resource in the POLES model as it has been produced for many years and does not require the same extent of fracturing or horizontal drilling as shale gas.

[189] Coal bed methane is also considered to be a non-conventional gas; however, its inclusion in POLES is scheduled to occur in conjunction with upgrades to the coal sector currently underway.

[190] POLES includes deepwater gas resources in European countries for United Kingdom and Norway and in the Mediterranean for Israel and Egypt, where fields have been significantly studied and reliable data are available; resources are not yet included for Cyprus and the Black Sea.

The emissions level is obtained by applying a carbon content factor to consumption according to the fuel and the sector, to which we remove, if necessary, certain amounts due to carbon sequestration or non-energy uses or carbon uptake in steel-making.

Biomass combustion is considered to be carbon-neutral; biomass associated with carbon capture and storage (CCS) technologies is considered to result in negative emissions.

NON-CO2 GHG EMISSIONS

The other greenhouse gases emissions that are simulated in POLES are the 5 GHGs identified in the Kyoto protocol on top of energy-CO2. They are: methane (CH4), nitrous oxide (N2O), perfluorocarbons (PFC), hydrofluorocarbons (HFC), and sulphur hexafluoride (SF6) gases. GWP figures used are from IPCC's Fourth Assessment Report (2007).

Table 29 Sectoral disaggregation for non-CO2 emissions balances, per country

Sector	GHG
Energy sector	
Gas production	CH4
Coal production	CH4
Oil production	CH4
Power T&D	SF6
Industry	N2O HFCs PFCs SF6
Buildings	CH4 N2O
Road Transport	N2O
Waste	CH4 N2O

Unlike CO2 emissions, which can be tracked with a great detail in POLES and related to the direct combustion of fuels, non-CO2 emissions are related to a policy-dependent emissions intensity index and one activity indicator: energy production or energy consumption. This activity is represented through an endogenous variable of the POLES model. The generic equation for non-CO2 emissions is:

Emissions = Emission Intensity Index parameter x Activity parameter x Trend

Where:

Emission Intensity Index parameter: a full equation that depends on gas- and sector-specific parameterization (maximum reduction potential, scaling factor), and on the carbon value that is included in the climate policy;

Activity parameter: depends on an Activity Indicator and a gas- and sector-specific elasticity;

Trend: Autonomous technological trend, i.e. assumption that technological developments will in most cases contribute automatically to reduce the emissions, even in the absence of any specific abatement policy.

Parameters were established in a sector-specific study conducted for POLES,[191] using data from US Environmental Protection Agency, IEA, RIVM and other sources and non-linear regressions. Typical scenarios with POLES do not modify these parameters, but the parameterisation allows the simulation of a dynamic reduction potential and a dynamic level of emissions.

The table below classifies the POLES series of non-CO2 GHG emissions, coming from a wide variety of activities related to fossil fuel production, transportation and use, industrial production, etc, and mapping them to categories in UNFCCC accounting tables.

Table 30 Emission categories for non-CO2 gases and corresponding activities

Data series	POLES Activity Indicator	UNFCCC Code	UNFCCC Category
CH4 from gas production	Conventional + non-conventional gas production (with the possibility of distinguishing the two)	1B2B1	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Natural Gas > Exploration
		1B2B2	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Natural Gas > Production Processing
CH4 from gas transport	Final demand for gas	1B2B3	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Natural Gas > Transmission
		1B2B4	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Natural Gas > Distribution
		1B2B5	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Natural Gas > Other leakage
CH4 from oil production	Conventional + non-conventional oil production	1B2A1	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Oil > Exploration
		1B2A2	Total Energy > Fugitive Emissions From Fuels > Oil And Natural Gas > Oil > Production
		1B2A3	Total Energy > Fugitive Emissions From Fuels >

[191] Greenhouse Gas Emission Control Strategies (GECS). 2002. DG Research 5th Framework Programme, Research Project EVK2-CT-1999-00010. Available at http://cordis.europa.eu/search/index.cfm?fuseaction=proj.document&PJ_RCN=4767127.

Data series	POLES Activity Indicator	UNFCCC Code	UNFCCC Category
			Oil And Natural Gas > Oil > Transport
CH4 from surface coal mining	Surface coal mining production	1B1A2	Total Energy > Fugitive Emissions From Fuels > Solid Fuels > Coal Mining And Handling > Surface Mines
CH4 from underground coal mining	Underground coal mining production	1B1A1	Total Energy > Fugitive Emissions From Fuels > Solid Fuels > Coal Mining And Handling > Undergroung Mines
CH4 from residential, agriculture, services	Final consumption of gas and biomass in buildings	1A4	Total Energy > Fuel Combustion Activities > Other Sectors
N2O from transport	Final consumption of oil in transport	1A3	Total Energy > Fuel Combustion Activities > Transport
N2O from industrial waste powerplants	Value added of industry	6	Waste
N2O from residential, agriculture, services	Final consumption of oil and biomass in buildings	1A4	Total Energy > Fuel Combustion Activities > Other Sectors
SF6 from electricity transmission	Power demand	2E + 2F	
CH4 from landfills	Urban population	6	Waste
N2O from industry	Value added of chemistry	1A2	Total Energy > Fuel Combustion Activities > Manufacturing Industries And Construction
		2	Industrial Processes
		3	Solvents And Other Products Use
HFCs from industry	Value added of other industry	2	Industrial Processes
PFC from other industries (inc. semi-conductors)	Value added of other industry	2 - 2C	Industrial Processes (exc. Metal Production)
PFC from aluminium	Value added of other industry	2C	Industrial Processes > Metal Production
SF6 from industry	Value added of industry	2 - 2E - 2F	Industrial Processes

2. Base case

The base case is the scenario we will start from for the calibration of the reference scenario for this project. It differs from a “Business As Usual” scenario, as it includes climate-related policies that change investment decisions (as described below) compared to the historical behaviour of most energy sector actors. It includes additional policies resulting in emissions reductions by 2030 of around 40% compared to 1990.

This "Base Case" forms the scenario on which sensitivities in relation to shale gas are assessed.

STORYLINE

Once the global recession is over, Business as Usual behaviour is restored rather quickly, and economic growth begins recovering from 2013 onwards. Sustained growth of China and other emerging countries is a powerful driver of energy demand. On the climate side, only current or already planned policies are maintained, including a 20% CO2 emissions reduction in the European Union by 2020 (CO2 emissions related to combustion and industrial processes). No additional policies are assumed on the international level, resulting in a CO2 emissions profile that continues to increase across the world and in emerging economies in particular. The future fuel mix is dominated by fossil fuels.

For the EU after 2020, a stylised scenario is assumed that sees a carbon price signal across all sectors ensuring that the EU reduces its GHG emissions (related to fossil fuel production and combustion and industrial processes) in 2030 by 40% compared to 1990 levels, see below for sectoral coverage). International fossil fuel prices increase significantly as world economic growth puts stress on supply.

DEFAULT POLICIES IN THE BASE CASE INCLUDE:

- a carbon value within Europe sufficient to reach a 20% reduction in CO_2 emissions by 2020 (represents the evolution of the EU ETS as well as support for low-carbon technologies and policies);
- no carbon value is included outside of Europe;
- extension and intensification of the carbon value throughout 2030 sufficiently so as to reach a 40% reduction of GHG emissions at the EU level compared to 1990,[192] as previously noted;
- policies already publicly declared, including those on nuclear (e.g., nuclear phase-out schedule of Germany) and renewables (e.g., feed-in-tariffs, subsidies, and support for biofuels in road transport), with a timeframe dependent on countries’ announced policies, but generally not extending beyond 2025 since few tangible policies are declared that far in advance.

Shale gas, once produced, is indistinguishable from natural gas from other sources (domestically produced or imported) and contributes to a single commodity that is gas. Policies that make renewables or other fuels comparatively more competitive than gas will result in a reduction of the demand for gas, be it conventional or not.

[192] This broadly aligns with the trajectory required to meet the EU’s 2050 GHG emission reduction target per the EC’s Low Carbon Economy Roadmap Communication and the Energy Roadmap 2050 Communication.

POLICIES & ASSUMPTIONS SPECIFICALLY PERTAINING TO SHALE GAS IN THE EU:

- Shale gas resources drawn from IEA, BGR, and most up-to-date national reports reviewed by ICF in the DG ENV study: shale gas is present in 16 EU Member States.[193] Resources (Ultimate Recoverable Resources) are constant through time and consider access based on Natura 2000 and population density (see Section **Error! Reference ource not found.** for more detail); resources progressively enter reserves and can then be produced.
- Moratoria on exploration and production are enacted in France, Bulgaria, the Netherlands, Luxembourg, the Cantabria Region of Northern Spain and the North Rhine Westphalia part of Germany[194]. In the modelling exercise, these moratoria are assumed to continue until 2015 (for France, it is likely to be 2017, but, in all cases, in the absence of firm information, the same assumption was made); beyond that date, no constraints in shale gas exploitation in these countries is assumed.
- There are no legal barriers imposed to shale gas exploitation elsewhere in the world throughout the modelling period.
- Technological costs are fixed at 2011 levels, but production costs rise over time with cumulative depletion of the resource, due to increasing extraction energy requirements (production cost curve as a function of the share of resource that has been produced); simultaneously, this effect is counter-balanced by technological learning effects that tend to decrease costs, and the production costs are a result of these two effects combined. Production cost curves have been assigned to EU shale gas based on the US production cost curve: on past experience and expert estimates on where it is headed in the future. Clean-up costs and other environmental costs are not included in these production cost curves.
- After extraction, shale gas is indistinguishable in the energy system from natural gas from other sources (domestic conventional, or imported) and hence treated in the same way.

ENERGY PRICES

Table 31 Energy price forecasts in the Reference scenario based on POLES modelling

	2000	2005	2010	2015	2020	2025	2030
International Oil Market Price ($05/bbl)	32.1	54.5	71.3	82.5	89.0	112.8	132.4
European Gas Market Price ($05/MMBtu)	4.1	6.9	5.1	7.0	6.9	8.2	8.7
European Coal Market Price ($05/t coal)	39	69	95	125	127	131	135

[193] Austria, Bulgaria, Denmark, Estonia, France, Germany, Hungary, Ireland, Latvia, Lithuania, Netherlands, Poland, Romania, Spain, Sweden, and United Kingdom. [Note: resource estimates for Spain are not included in the POLES output shown here; they will be added once final production costs for the base case and policy scenarios are run through the model.]

[194] Shale gas resources in the North Rhine Westphalia are estimated by ICF to represent about 10-15% of Germany's total; to be conservative, 15% is assumed in this analysis.

MACRO-ECONOMIC ASSUMPTIONS

Population data and growth rates are included from the UN Population Division medium fertility scenario from 2011.[195] GDP data and growth rates are included from:

- World Bank (values for 2000-2011);[196]
- IMF (values for 2012-2017);[197] and
- CEPII (values for 2018-2030).[198]

Assumptions on population and GDP growth rates are provided in the tables below.

Table 32 Population growth rates

		2000	2005	2010	2015	2020	2025	2030
Austria	%	0.12	0.72	0.23	0.12	0.12	0.10	0.04
Belgium	%	0.25	0.55	0.77	0.24	0.24	0.22	0.20
Bulgaria	%	-1.80	-0.53	-0.55	-0.67	-0.73	-0.81	-0.85
Cyprus	%	1.43	1.13	0.07	1.01	0.82	0.67	0.53
Czech Republic	%	-0.09	0.19	0.36	0.21	0.17	0.07	-0.05
Denmark	%	0.34	0.27	0.38	0.32	0.31	0.27	0.19
Estonia	%	-0.45	-0.22	-0.05	-0.08	-0.14	-0.25	-0.33
Finland	%	0.21	0.34	0.46	0.29	0.26	0.18	0.08
France	%	3.65	0.75	0.52	0.49	0.43	0.39	0.36
Germany	%	0.15	-0.06	-0.24	-0.19	-0.12	-0.18	-0.23
Greece	%	0.32	0.38	0.32	0.19	0.10	0.04	0.03
Hungary	%	-0.26	-0.20	-0.14	-0.15	-0.16	-0.18	-0.22
Ireland	%	1.34	2.20	0.50	1.06	0.91	0.76	0.67
Italy	%	0.05	0.74	0.48	0.11	-0.03	-0.07	-0.09
Latvia	%	-0.75	-0.53	-0.53	-0.36	-0.40	-0.45	-0.47
Lithuania	%	-0.89	-0.62	-0.56	-0.40	-0.37	-0.38	-0.43
Luxembourg	%	1.35	1.54	1.62	1.22	1.16	1.03	0.88
Malta	%	0.52	0.64	-0.08	0.28	0.18	0.08	-0.04
Netherlands	%	0.76	0.23	0.49	0.26	0.21	0.17	0.11
Poland	%	-0.53	-0.04	0.09	0.03	-0.02	-0.12	-0.27
Portugal	%	0.51	0.45	0.10	-0.03	-0.21	-0.31	-0.33
Romania	%	-0.07	-0.23	-0.18	-0.23	-0.27	-0.32	-0.38
Slovak	%	-0.12	0.08	0.27	0.16	0.12	0.02	-0.13

[195] Available at http://esa.un.org/unpd/wpp/Excel-Data/population.htm.
[196] Available at http://data.worldbank.org/indicator/NY.GDP.MKTP.CD.
[197] Available at http://www.imf.org/external/ns/cs.aspx?id=28.
[198] Available at http://www.cepii.fr/CEPII/en/bdd_modele/presentation.asp?id=11.

Republic								
Slovenia	%	0.18	0.17	0.64	0.19	0.08	-0.03	-0.11
Spain	%	0.84	1.65	0.38	0.51	0.42	0.28	0.18
Sweden	%	0.13	0.36	0.87	0.54	0.56	0.47	0.34
United Kingdom	%	0.36	0.60	0.68	0.60	0.56	0.53	0.45

Table 33 GDP growth rates

		2000	2005	2010	2015	2020	2025	2030
Austria	%	2.16	2.40	2.31	2.15	1.52	1.16	1.02
Belgium	%	4.19	1.73	2.27	1.57	1.40	1.05	1.05
Bulgaria	%	11.15	6.36	0.20	3.50	3.76	2.92	2.69
Cyprus	%	5.10	3.91	1.04	2.50	2.88	2.76	2.68
Czech Republic	%	3.65	6.32	2.35	3.62	3.23	2.92	2.87
Denmark	%	3.35	2.45	1.75	1.90	1.49	1.12	1.06
Estonia	%	7.36	9.43	3.10	3.79	4.51	4.92	4.76
Finland	%	4.51	2.92	3.64	1.98	1.64	1.28	1.22
France	%	3.73	1.83	1.48	1.90	1.77	1.54	1.52
Germany	%	2.15	0.68	3.69	1.29	0.90	0.45	0.39
Greece	%	3.17	2.28	-3.52	3.15	2.86	2.82	2.71
Hungary	%	5.74	3.96	1.26	2.26	2.63	2.97	2.74
Ireland	%	10.16	6.02	-0.40	2.84	2.53	2.14	2.05
Italy	%	3.67	0.66	1.30	1.00	0.75	0.29	0.29
Latvia	%	7.01	10.60	-0.34	3.53	4.47	4.92	4.86
Lithuania	%	4.02	7.80	1.33	3.72	4.46	4.92	4.77
Luxembourg	%	10.04	5.43	2.68	2.89	2.73	2.18	1.87
Malta	%	5.50	4.01	3.15	2.22	2.53	2.77	2.77
Netherlands	%	4.30	2.05	1.69	1.83	1.59	1.22	1.10
Poland	%	4.35	3.62	3.94	3.90	3.47	3.04	2.85
Portugal	%	7.49	0.76	1.39	1.90	1.58	1.67	1.68
Romania	%	2.20	4.17	0.95	3.98	3.75	3.44	3.16
Slovak Republic	%	1.39	6.66	4.24	3.90	3.65	3.56	3.21
Slovenia	%	4.64	4.01	1.38	1.90	2.03	1.96	1.84
Spain	%	5.09	3.61	-0.14	1.65	2.03	2.18	2.14
Sweden	%	5.01	3.16	5.63	3.00	2.06	1.67	1.56
United Kingdom	%	5.28	2.17	1.35	2.61	2.43	1.95	1.79

Appendix F – Assumptions on uptake rates of GHG abatement techniques

1. EU Conventional Gas techniques

The EU currently produces 33% 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. Consultation with the UK Onshore Operators Group (UKOOG)[199] indicates that there is relatively little onshore conventional O&G activity in Europe. In the UK, around 95% of all onshore activity is oil-related. There are only 3 companies operating onshore gas activities. The majority of activity is currently offshore.

The offshore gas industry is highly concerned with safety issues and, as a result, techniques and practices that are in place are not directly comparable to onshore activity. The UK offshore safety standards are recognised as "gold standard"[200] and these have been used as the basis for onshore O&G regulatory framework in the UK.

As there is little onshore activity in EU, we have drawn on available US data to arrive at assumptions of the likely uptake rates of abatement techniques in future shale gas exploration and production in Europe.

2. Business as Usual

Under no legislation, the adoption rate of the mitigation technologies will be a function of both the economic viability and environmental benefit of the different mitigation technologies. Producers often have multiple investment opportunities and limited capital to invest in revenue improvement (i.e. drilling new wells), expense reduction and environmental benefit projects. These mitigation technologies are often considered by companies as expense reduction or environmental projects. Hence, although the payback period is relatively short, some companies would choose to invest in revenue improvement projects instead. Conversely, other companies will implement the mitigation technology because it is an environmental benefit with a short payback period. Therefore, the expert experience with these mitigation technologies has been used to assess the BAU adoption rate.

Table 34 Mitigation technologies used to assess the BAU adoption rate

Technology	BAU Adoption Rate %	Methane Savings per Unit	Methane Savings per Well
Reduced emissions completions	50%	10,800 Mcf/ well	10,800 Mcf/ well
Directed Leak Inspection and Measurement	10%	385 Mcf/ device/year	385 Mcf/year[201]

[199] Discussion with K Cronin (June, 2013)

[200] http://www.oilandgasuk.co.uk/ProposedEURegulation.cfm

[201] Assuming one leaking component per well.

Convert natural gas driven chemical pumps	10%	1,342 Mcf/year	121 Mcf/year
Install flash tank separators in dehydrators	10%	3,553 Mcf/year	320 Mcf/year
Install plunger life systems in gas wells	15%	4,590[202] Mcf/year	4,590[203] Mcf/year
Convert high bleed pneumatic devices	40%	125 Mcf/year	166 Mcf/year
Rod packing replacement in reciprocating compressors	40%	865[204] Mcf/year	118 Mcf/year
Install vapor recovery units on storage tanks	10%	50,000 Mcf/year	6,250 Mcf/year
Replace wet seals in centrifugal compressors	40%	45,120 Mcf/year	451 Mcf/year
Install wet seal degassing recovering system in centrifugal compressors	0%	45,120 Mcf/year	451 Mcf/year

REDUCED EMISSIONS COMPLETIONS

According to a recent EPA analysis, around 50% "of [U.S] hydraulically fractured gas well completions and recompletions not already under state regulation and with sufficient pressure to perform a REC will implement RECs voluntarily". ICF assumed that EU shale gas production experience would be similar to that in the U.S. The economics of implementing a REC in the EU would most likely be better than the U.S. because of the higher market price of the gas recovered, hence the voluntary implementation of RECs would be at least that of the U.S.

REPLACE WET SEALS IN CENTRIFUGAL COMPRESSORS

New centrifugal compressors will be required when shale gas operations come online. More than 90% of new centrifugal compressors come equipped with dry seals.[205] Nevertheless, old compressors that are used in existing operations will be leveraged in new shale gas operations. As a result, ICF estimates that 40% of all centrifugal compressors will employ dry seals.

INSTALL WET SEAL DEGASSING RECOVERING SYSTEM IN CENTRIFUGAL COMPRESSORS

Installing wet seal degassing recovering systems in centrifugal compressors is still not a commercial technology; the technology is 5-10 years from commercialization.

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[202] The Natural Gas Star Lessons learned on plunger lifts reports average savings of 11,475 Mcf per well per year. Assuming that liquids unloading arises over the last four years of a well's life, the levelized methane savings can be computed as follows: 11,475*4/10 = 4,590 Mcf

[203] The Natural Gas Star Lessons learned on plunger lifts reports average savings of 11,475 Mcf per well per year. Assuming that liquids unloading arises over the last four years of a well's life, the levelized methane savings can be computed as follows: 11,475*4/10 = 4,590 Mcf

[204] Assuming new rings and rods are replaced every three years, the operator would have to go through the investment cycle four times.

[205] http://www.epa.gov/gasstar/documents/ll_wetseals.pdf, Page 3.

3. **Policy option: Voluntary approach**

Under this option, industry would be encouraged to develop their own approach to minimising on-site fugitive GHG emissions. This could take a form of information exchange, guidance or development of an industry standard. This approach has resulted in significant emission reductions in North America with the Natural Gas Star Program. However, there may be concern from civil society that an industry-led approach may not lead to best practice being adopted. In order to mitigate these concerns, this approach could be accompanied by the announcement of EU intervention in case the voluntary approach is not robust enough to lead to emissions reductions.

As a result, this scenario is considered to result in a higher level of uptake rate than the BAU scenario.

4. **Policy option: amendment to EIA Directive**

Under this option, the activities listed in Annex 1 of the IED would be revised to include shale gas activities. This would mean that any proposed exploratory or commercial development is subject to mandatory EIA. Nonetheless, it is noted that this option would not guarantee emission reductions as mitigation techniques are not part of an EIA. Instead, in the event of a full EIA, developers are obliged to provide required information, including a description of measures to avoid, reduce and, if possible, offset any significant adverse effects. But there is no clear obligation to do so. Implementation of measures is not explicitly required. This depends on the national implementation of the EIA Directive. There is also no clear definition of “significant” adverse effects. As a result uptake rates of mitigation technologies are assumed to be the same as in the BAU scenario.

5. **Policy option: amendment to Industrial Emissions Directive**

Under this option, the Industrial Emissions Directive would be amended to include shale gas activities. A Best Available Techniques Reference Document (BREF) would be prepared setting out the best available techniques (BAT) for mitigation of environmental (including climate) impacts of shale gas extraction. ‘BAT conclusions’, which would form the basis of permits under the IED, cannot be deviated from, except in specific well justified cases. The BREF document would be updated at a pre-determined frequency offering the opportunity to include new technical developments in the sector. This option would lead to more emission reductions given that the emission limit values would be set based on BAT conclusions. However, flexibility would still remain as the level of the permitting of the installations concerned. The BREF document would be updated/renewed at a pre-determined frequency (e.g. every 6 years) offering the opportunity to include new technical developments in the sector.

This option provides high certainty of achieving significant emission reductions given that the emission limit values would be set based on BAT conclusions. As a result, uptake rates of mitigation technologies are assumed to be the same as in new legislation policy scenario (see section below).

6. **Policy option: New legislation**

This scenario is assumed to be the most stringent of the policy options under consideration. In this option legislation would make any necessary amendment to existing legislation (for example in respect of the IED and EIA Directive) and it could also provide for other elements such as

monitoring requirements. As a result, there would be a high degree of certainty in achieving the desired level of fugitive GHG emission reductions since the rule would specifically target shale gas emissions.

The table below provides adoption rates of the key GHG mitigation technology options under this policy option.

Table 35 GHG mitigation technology options

Technology	Constraints/alternatives	New Legislation Adoption Rate %
Reduced emissions completions	Low pressure wells, wildcat wells	90%
Directed Leak Inspection and Measurement	Difficulty in enforcing this mitigation technology.	60%
Convert natural gas driven chemical pumps	Some dehydrators might be located in remote areas where there is no access to electricity; or solar power is too intermittent to be relied on to power the pumps.	90%
Install plunger life systems in gas wells	Alternative technologies to deal with liquids unloading (ex: electric pumps)	25%
Install flash tank separators in dehydrators	Some producers may opt to reduce triethylene glycol (TEG) as an alternative mitigation option	100%[206]
Convert high bleed pneumatic devices with low bleed pneumatic devices	Emergency shutdown valves and some other large valves cannot be replaced by low bleed pneumatic devices. This is because some of these large controllers require a fast response to process changes that can only be achieved with high bleed devices. [207]	80%[208]
Rod packing replacement in reciprocating compressors	None	100%
Install vapour recovery units on storage tanks	Volume of gas vapour needs to be sufficient to warrant a vapour recovery unit.	50%
Replace wet seals in centrifugal compressors with dry seals	Wet seal compressors with degassing recovering systems will take away some of the market share from dry seal compressors.	90%
Install wet seal degassing recovering system in centrifugal compressors	New technology, 5-10 years from commercialization.	10%

[206] Operators would install flash tank separators or reduce triethylene glycol (TEG) circulation.

[207] EPA Lessons Learned, Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry, P.4. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf

[208] EPA Lessons Learned, Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry, P.2. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf

REDUCED EMISSIONS COMPLETIONS

Under new legislation, low pressure wells and wildcat wells will be exempt from performing reduced emissions completions. According to the NSPS Technical Support Document, approximately 4% of all gas U.S. well completions are expected to be associated with wildcat and delineation wells.[209] The NSPS set a pressure threshold of 34.5 bar (500 psi), under this pressure the well is deemed a low pressure well and REC's are not required.[210] As stated in Appendix B of the interim report:

> "The pressure of the natural gas entering a REC decreases resulting in a lower pressure natural gas exiting the REC. The pressure of the natural gas exiting the wellhead must be high enough to incur the "pressure drop" along the REC and be higher than the gathering pipeline pressure."

The EPA estimated that 8% of all well completions will be associated with low pressure wells. This would imply that 88% of all U.S. well completions are expected to perform RECs under the new NSPS rule. Assuming that EU shale gas production will exhibit similar behaviour to US shale gas production; approximately 90% of EU well completions will perform RECs.

INSTALL PLUNGER LIFE SYSTEMS IN GAS WELLS

The adoption rate in this case looks at all producing wells. This includes wells that require liquids unloading and those that do not. In the U.S., the EPA inventory estimated that 41.3% of all wells require liquids unloading. Plunger lifts are often the lowest cost option to deal with liquids unloading. When the pressure of the well drops, plunger lifts no longer become effective and alternative technologies such as submersible pumps may be deployed. It is worth noting that the EU may have a different profile with wells that require liquids unloading. The percentage of wells that require liquids unloading is going to depend on the age of the wells and the characteristics of the reservoirs.

INSTALL VAPOUR RECOVERY UNITS ON STORAGE TANKS

According to an EPA analysis, 50% of operators would install vapour recovery units and 50% would install combustors to reduce tank VOC emissions.[211] According to the EPA, VRUs present operational challenges that force operators to opt for combustors. Combustors reduce VOC and methane emissions however; they create CO_2emissions. Given that the EC is concerned with GHG emissions (NSPS was concerned with VOC emissions), combustors for the EC's purposes is not truly a methane recovery technology and as a result, it was excluded in this analysis.

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[209] http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf, Page 4-4.

[210] http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

[211] EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution Technical Support Document, page 7-9. http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf