Shale Gas – Environmental Aspects, Technical Parameters and Explorations in TIMER

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Summary
Over the last ten years the shale gas industry in the U.S. has flourished. At the moment shale gas makes up 34% of the total US natural gas production, and the possibility of the US becoming a net exporter of natural gas is becoming increasingly likely (EIA, 2012a). The economic success has inspired other countries to start investigating their own domestic shale gas potential. However, the environmental consequences of shale gas production are still a fiercely debated matter and it is still uncertain to what extent other countries will be able to replicate the success experienced in North America. Also the effects of extra unconventional gas in the energy mix are still up for discussion, where proponents point at the possibilities of a bridge fuel and opponents fear for substitution of renewables. This research tries to give some insight into the matter by giving an extensive literature review of the technical and environmental consequences of shale gas development. Furthermore it will investigate which role unconventional gas could play in the future by analyzing several shale gas development scenarios in the TIMER model on the basis of new supply cost curves.

In every assessed scenario conventional gas stays dominant over unconventional gas production in the first half of the 21st century indicating that for most regions conventional gas supplies will be cheaper than unconventional gas. When unconventional gas production starts to grow it mostly substitutes for coal use in the electricity sector. However due to the fact that also renewable energy sources are substituted, notably modern biofuels, emission reductions are limited if no additional climate policy is introduced. In a world where unconventional gas is globally developed and where the carbon tax is introduced global CO_2 emissions are 11 percent lower. This Indicates that if unconventional gas supplies can be globally produced against lower costs, more emission reductions are achieved compared to the reference scenario even though the carbon tax stayed the same.

With regards to the technical and environmental parameters the most important findings are mentioned underneath.

Hydraulic fracturing is a technique not limited to shale gas developments but is also applied to for example t tight sands gas wells and conventional gas wells. Characteristic for shale gas development is however the combination of horizontal drilling and hydraulics fracturing which is necessary to get a commercial flow rate where as tight sands and conventional gas wells will often be vertically fracked. The amount of fracking fluid used and the length over which the fracking is performed is therefore often lower in these cases.

Reserve and resource estimates with respect to shale gas estimates are still subjected to large uncertainties. Production data is mostly limited to North America and for shale plays it is hard to estimate flow rates from seismic data alone. Current technically recoverable resource estimates lie between 7000-8000 EJ which equals 64-72 years of current production although it could very well be that large revisions follow as more data becomes available over time.

Multiple studies have linked contamination of groundwater and private water wells to fracking operations in the area in the United States. Several contamination routes are possible. Migration through the formation seems unlikely, compromised well integrity could be a more likely

explanation. Ingraffea (2012) has studied this in Pennsylvania and found that in 6 to 7 percent of the cases the casings were compromised.

Hydraulic fracturing in shale layers does not necessarily cause a high risk of seismic activity, because pressures are exerted only for a short period of time on the formations, the low permeability of shale formations prevents compaction in the underground and the flow back phase allows for pressure relief. However, if hydraulic fracturing happens near a pre stressed fault, it can induce a bigger earthquake. This has occurred in the past.

Most studies find comparable emissions between shale gas and conventional gas production. Howarth et al (2011) is the only one who found an emission factor for shale gas as high as coal, this is due to high assumed fugitive methane emissions. He assumed zero flaring and this does not seem to correspond with current practices.

Shale gas wells have a high decline rate. In the first year the production rate can fall by as much as 70 percent. Even though the decline rate moderates after time, it is still uncertain how this will behave in the long term. Since this determines a large part of the EUR of a well, it is an important factor to assess the profitability of a well. There is currently some debate on what lifetimes of shale gas wells will be. Long term data is missing, so no conclusive answer can be given.

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1 Introduction

1.1 Increasing importance of gas

In the WEO 2011 the IEA released a special report called the 'Golden Age of Gas'. This report examined key factors that could secure a prominent place in the energy-mix for natural gas as well as current trends in the gas market. The recent revolution in the natural gas market in the United States due to the economic success of shale gas extraction, the expansion of LNG-trade and the increase in demand over the last few years indicate a promising future for natural gas (IEA, 2011). The projected fast-growing demand of natural gas can partly be explained by leading institutions as the IPCC and the IEA calling natural gas a bridging, or transition, fuel which can play a key role in resolving the dilemma of meeting growing energy demand and reducing greenhouse gas (GHG) emissions (IPCC, 2007; IEA, 2011). The efficiency and flexibility of gas-fuelled powerplants, combined with low fuel costs and a promising resource base could make gas a suitable candidate to solve the intermittency currently associated with renewables. The relatively widespread geographical distribution of unconventional gas could create changes in the current situation where a vast amount of the fossil reserves is located in a small, often politically unstable, area. The exploitation of domestic unconventional gas reserves could reduce concerns about energy security and depletion of conventional gas supplies.

1.2 Current and projected natural gas use

Natural gas currently makes up more than one fifth of the world's total primary energy supply (TPES) (see Figure 1 - World Total Primary Energy Supply (TPES) by fuel type. Other includes geothermal, wind, solar, heat etc. Data from 2010. (IEA, 2012) . Most of the natural gas used is produced by OECD countries (35,6%), followed by non-OECD Europe and Eurasia (25,7%) and the Middle-East (15,4%) (IEA, 2012). Natural gas is mainly used for power (including heat) generation (around 40%). Building heating and industry are the two other main consumers accounting for respectively, 20-25% and 12-15% of the total natural gas use.

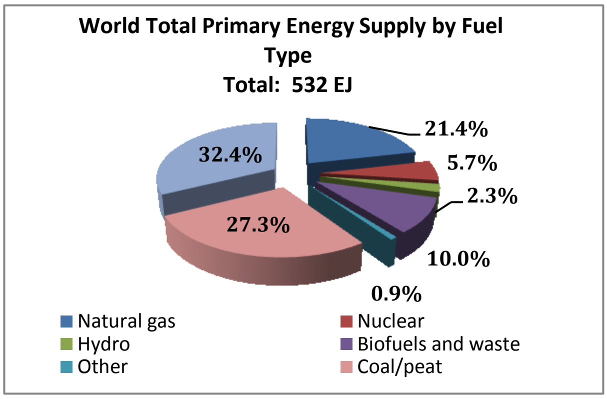

Figure 1 - World Total Primary Energy Supply (TPES) by fuel type. Other includes geothermal, wind, solar, heat etc. Data from 2010. (IEA, 2012)

The share of natural gas in the energy mix has grown over the years, in 1973 (the earliest year in the IEA databases) the share of natural gas in the world TPES was 16.0%. Compared to the other fuels, natural gas has experienced the largest increase in market share in the period 1973-2010 (+5,4%) (IEA, 2012).[1]

Prospects for natural gas use seem promising, it is the fastest growing fossil fuel in the IEA WEO 2012 expected to come from non-OECD regions as their relatively young gas-infrastructure matures and they become more developed. China, India and the Middle-East are expected to show the biggest increases in demand growth, although demand grows in all assessed regions (see Figure 3 - Natural gas demand for different regions in the New Policies scenario. (IEA/OECD, 2012) (IEA/OECD, 2012).

projections and the only fossil fuel for which demand grows under all scenarios (see Figure 2 - World natural gas demand for different IEA scenarios. Full descriptions of the scenarios can be found in the

[1] Nuclear +4.8%; Hydro +0,5%; Biofuels and waste -0,5%; Other +0,8%; Coal/peat +2,7%; Oil -13,7%

IEA WEO 2012. (IEA/OECD, 2012)). Power generation is expected to be the main driver of this process. Increases in demand are mainly

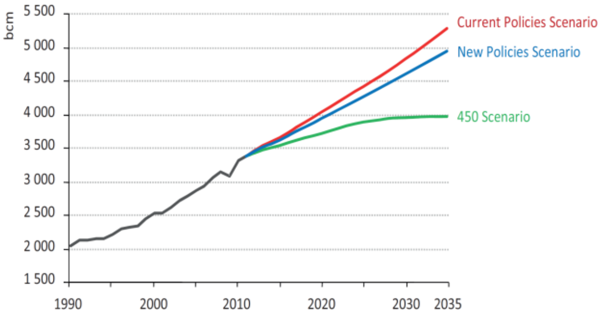

Figure 2 - World natural gas demand for different IEA scenarios. Full descriptions of the scenarios can be found in the IEA WEO 2012. (IEA/OECD, 2012)

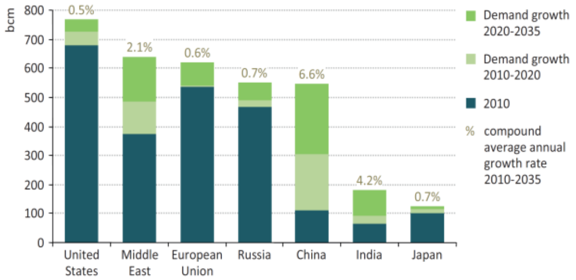

Figure 3 - Natural gas demand for different regions in the New Policies scenario. (IEA/OECD, 2012)

1.3 Shale gas revolution US

In this dash for gas the attention for unconventional gas is increasing. Over the last ten years the shale gas industry in the U.S. has flourished. The developments in horizontal drilling and hydraulic pressurized fracking combined with high gas prices made the extraction of natural gas from low permeable shale layers profitable (Rogers, 2011). Where at the beginning of the 2000's domestic production in the U.S. started to decline and large scale LNG imports seemed to be inevitable in the long-term, domestic production started to rise again in 2006 due to shale gas extraction (Rogers, 2011). At the moment shale gas makes up for 34% of the total US natural gas production, and the possibility of the US becoming a net exporter of natural gas is becoming increasingly likely (EIA, 2012a). Proven wet natural gas reserves in the US have increased from 186,5 trillion cubic feet (tcf) in 2000 to 317,6 tcf in 2010 (a 170% increase)[2]: next to that, natural gas prices have lowered spectacularly in the US due to increased supplies (see Figure 4 - U.S. Natural gas price at the Henry hub in \$/MMBTU and U.S. shale gas production in tcf (1MMBTU ≈ 1.055 GJ; 1 tcf ≈ 1.055 EJ). (The Economist, 2013) (EIA, 2012b).

Figure 4 - U.S. Natural gas price at the Henry hub in \$/MMBTU and U.S. shale gas production in tcf (1MMBTU ≈ 1.055 GJ; 1 tcf ≈ 1.055 EJ). (The Economist, 2013)

An IHS study estimated that up to 2010 the shale gas industry in the US has created over 148,000 direct jobs, next to that a large amount of indirect and induced jobs could have been created although these are more speculative (IHS, 2011; Kinnaman, 2011)). The chemical industry has signalled interest in expanding US capacity due to the low domestic gas prices (IHS, 2011). Furthermore the shale gas revolution has rendered the build-up capacity of LNG regasification plants useless as imports have dropped and are not expected to rise anytime soon (in 2009 only 9% of the installed regasification capacity in the US was used). For this reason there have been eight applications awaiting approval to transform the regasification plants to LNG liquefaction plants to be

[2] Reserve-to-Production Ratios (RPR) for natural gas in the US have increased from 9,87 to 12,61 years in the period 2000-2010 (BP, 2013).

able to export the domestic gas (Rogers, 2011; Ratner, 2013)[3]. North America seems to be getting a hold on the idea of energy independence and the resulting economic consequences have inspired other countries to start investigating their domestic shale gas potential.

1.4 Controversy

The environmental consequences of shale gas production are however still a fiercely debated matter. Proponents point at the abundant supplies of cheap domestic gas which could be used as a bridge fuel to a carbon-neutral economy in the long-term. Opponents are worried about (amongst other concerns) spatial problems, possible groundwater pollution, increased risk of earthquakes, methane leakage and decreased investments in renewables. This debate has so far stopped major developments of shale gas production in most parts of Europe.

Methane is a very potent greenhouse gas. Opponents point out that the process of shale gas production, mainly possible fugitive methane emissions, could make the carbon-footprint of shale gas as high as that of coal (Howarth et al., 2011An increasing amount of shale gas in the natural gas mix would render it useless as a bridge fuel in this case.

The same applies for the contamination of aquifers which could lead to toxic chemicals ending up in the drinking water supply. In the US several instances of failing of casings, installed to prevent leakage to aquifers, and blow outs of shale gas wells have been documented. Anecdotes of households near shale gas operations having problems with methane leakage to their faucets have created further public resistance against shale gas developments. Furthermore fracking was excluded from the Cleanwater-act which made sure natural gas producers did not need to disclose information about chemicals they were using. This became known as the 'Halliburton loophole' and led, next to public debate also to poor monitoring of environmental impacts in the first years of shale gas production (Stevens, 2012). The lack of data with respect to pre and post shale gas situations have made it hard to draw conclusions about the environmental impacts of shale gas and therefore the academic world seems still seems a bit divided (Stevens, 2012).

Another factor leading to debate is the profitability of shale gas. The 'Shale gale' led to huge investments in production capital. The resulting flow of gas led to such a drop in prices producers were selling at a loss. The break-even price of shale gas in the US is around 4-5.70 $/Mcf depending on the specific play (Jacoby et al., 2011).[4] Wellhead prices in the U.S. for natural gas were at 3.35 $/Mcf as of November 2012 (EIA, 2012c). The idea of the 'Shale Burst' is becoming more eminent.
A lot of shale gas plays show fast decline rates leading to the idea that the reserve estimates and economic feasibility of shale gas are overstated (Urbina, 2011). The feasibility of these claims is hard to verify as shale gas is a relative new phenomenon. Although decline rates seem to moderate after a year of production it is hard to say what will happen in the long-term (Jacoby et al., 2011). The industry responded to the articles written by Urbina with a large scale PR-machine and the debate has since then become more vicious and polarized (Stevens, 2012).

1.5 Overview of exploratory drillings in other parts of the world

At the moment shale gas development is mostly limited to the U.S. However, promising initial assessments combined with the success in Northern America has sparked interest in order regions. China, which energy demand is rising steeply, might have the biggest shale gas reserves in the world and there a plans to produce 6.5 bcm in 2015 (The Economist, 2011). In Mexico some exploratory wells were drilled which created enthusiasm, however till today no wide scale development took place (The Economist, 2011). Although the rest of South-America is also expected to have substantial

[3] Over the period 1986-2007 gas imports in the United States have continuously risen from 816 PJ to a peak of 5008 PJ in 2007, since then imports have steadily declined to a value of 3411 PJ in 2012 (EIA, 2013c).
[4] 1 Mcf ≈1.055 GJ (M=1000)

reserves, only in Argentina there seems to be some serious efforts to develop a shale gas industry (KPMG, 2011).

South-Africa is also expected to hold large reserves and the government lifted its moratorium in September 2012, exploration drillings are expected to start in second half of 2013 (Burkhardt, 2013). Poland is expected to have the biggest shale gas reserves in Europe and is in the furthest stage of commercial extraction compared to the rest of Europe (Shale gas Europe, 2013). Also India is expected to hold big reserves and explorational drilling has already started (The Economist, 2011). Next to that the parliament in the Netherlands permitted exploratory drills very recently, but they were revoked again after protests from the electorate of one of the coalition partners. The UK has, after a troublesome start-up, again started to exploit its shale gas reserves (KPMG, 2011)[5]. Also the government of Spain is enthusiastic and explorations have started in the hope shale gas can help resolve the current economic crisis (Shale Gas Europe, 2013). Within Sweden there have been some minor explorations but for the time being the government does not seem to be too keen on wide-scale shale gas development. (Philippe & Partners, 2011) In the Middle-East not much is happening with respect to shale gas, probably due to the extensive nature of conventional reserves and the scarceness of huge amounts of water needed for the fracking process, although the potential in Algeria and Libya for shale gas reserves looks promising (EIA, 2011). The chief executive of Saudi Aramco, Saudi-Arabia's national oil and gas company, has however announced that it will start drilling seven exploratory wells this year (Hall, 2013).

1.6 Impact of wide scale shale gas development

Conventional fossil fuels are unevenly distributed throughout the world, with the majority located in a relative small area. Traditionally this has led to power struggles, monopolisation and concerns about energy security. Since energy is a vital component for a modern day economy , the geopolitical landscape is for a great deal shaped by energy relations. Energy can be used as a political weapon seen in for example the oil crisis 1973 or the more recent disruption of supply of natural gas to Ukraine orchestrated by Russia. Since initial assessments show a much more diverse distribution of shale gas reserves it is expected that this will lead to a reform in current geopolitical relations. Long lifetimes of natural gas fired-plants could facilitate that a growing share of natural gas in the energy mix is likely to stay there for several decades. The availability of cheap domestic fuel might also reduce the upcoming for renewables as the feeling of necessity slowly disappears in the public arena due to a renewed abundance of cheap fuel. The shale gas revolution in the US has already led to lower prices in Europe due to the oversupply of LNG originally destined for the North American market (Stevens, 2012). The wide variety of consequences shows that further developments in the shale gas market outside of the United States have the potential to change the energy and geopolitical landscape of the future.

1.7 Main aim of the research

Till today shale gas development is limited to North America and it is still uncertain to what extent it might spread to other parts of the world and what the consequences of different development scenarios on the energy mix and the climate will be. Next to that there still seems to be confusion about the environmental consequences of shale gas development as well as the economic viability.. This thesis will therefore provide an overview of the technical and environmental aspects of shale gas development. Next to that some modifications will be made to the TIMER model to properly reflect shale gas in the model which will be used for scenario-based assessment of several shale gas development pathways.

[5] After some seismic activity occurred at the blackpool aquifer the company conducting the drills decided to stop production to allow further investigations, however no relations between the drillings and the earthquakes have been found. (KPMG, 2011)

1.8 Position within the field of Energy Science

Energy Science focusses on the technical, economic and social side of the energy system. Important aspects within this field are the consequences of energy production and use for the people, environment and future generations. This thesis provides insight into how shale gas development may influence the energy-system in the future. Shale gas has been called the biggest game changer in the energy sector and is attracting massive attention at the moment. Due to it being a relative recent phenomenon little scenario-based approaches for possible future pathways of shale gas have been developed. This research can contribute to understanding which factors enable shale gas development and which consequences increased development of shale gas will have.

1.9 Methodology

The research can be divided in roughly two parts:

Identify key parameters with respect to the technical, economic and environmental sides of shale gas compared to the current way natural gas is modelled within the TIMER framework. In order to incorporate shale gas into the TIMER model several parameters currently incorporated in the model will need to be adjusted.

Adjust the TIMER model to incorporate the findings of key parameters to make it suitable for assessing shale gas developments. Next to that, adjust parameters in order to conduct a scenario study based upon several storylines. Relevant parameters are the resources estimates and production costs of conventional and unconventional gas. Next to that several emissions scenarios with respect to methane emissions in the production phase are assessed.

1.10 Reading guide

Chapter 2 will focus on the technologies associated with natural gas extraction, especially horizontal drilling and hydraulic fracturing. In chapter 3 the several resource and reserve assessments with respect to natural gas will be assessed along with a comparison to current incorporation in the TIMER model. Next to several cost supply cost curves are presented which show the estimated production cost of portions of the resource base. Chapter 4 gives a literature overview of environmental aspects of shale gas development as well as the issues surrounding the productivity of wells. For analysis purposes a simple excel model simulating the an average shale gas well in the Barnett Shale is constructed which is used to test how sensitive the Net Present Value is to changes in some key-parameters. Chapter 5 gives an introduction to the TIMER model and describes the implemented modifications as well as the different scenarios which were assessed. In chapter 6 the results of the TIMER model study are presented. Chapter 7 gives an overview of the most important findings from the literature study on the technical and environmental parameters and discusses the most important model outcomes along with the limitations of the research.

2 Technology Description

In this section a brief overview of the characteristics of several types of gas (next to shale gas) will be provided next to an overview of the technique of hydraulic fracturing and gas production processes in general. In later sections expected improvements in this technique as well as the environmental, economic and social factors associated with this extraction will be discussed in more detail. It should be noted that shale gas extraction itself is not a new technique. The first shale gas well was already taken into production in 1821 and horizontal drilling and fracking were first performed in the 30's and 40's, it was however only recently it took off at an industrial scale.

2.1. The origins of oil and gas

Oil and gas can be formed when organic material under the influence of high pressure and high temperatures is converted to hydrocarbons. When organic materials become deposited into the sediment and subsequently buried in the earth's crust, the resulting rising temperature and pressure can transform the carbohydrates present in organic material to kerogen. With the right combination of temperature and pressure this kerogen can then be cracked into a variety of hydrocarbons. The temperature and the carbon content of the formation determine the length of the hydrocarbons and therefore dictates if primarily methane (CH_4), oil or intermediates products called condensates or natural gas liquids are formed (ethane(C_2H_6), butane (C_3H8), propane (C_4H_{10}),..). Conditions within a formation are often not homogenous over time and place which can lead to a combination of oil, gas and natural gas liquids present within a formation.

A conventional natural gas or oil play will consist of three main components: a source rock, a reservoir rock and a cap rock. In this situation the source rock is the basis where the hydrocarbons are formed from kerogen (e.g. a shale layer), the reservoir rock is a permeable layer above the source rock which facilitates upward migration of the hydrocarbons (e.g. a sandstone layer) and the cap rock is an impermeable layer which functions as a seal or trapping mechanism under which oil gas can accumulate (e.g. salt layer). For unconventional gas the situation is slightly different. There are many types of unconventional gas: shale gas, tight gas, coalbed methane, deep gas, aquifer gas, dissolved gas and methane hydrates. Some of these types are displayed in the figure below (see Figure 5). The most important ones will be discussed in more detail:

- Shale gas is gas trapped in shale layers which consist of fine-grained sedimentary rock. Shale formations consist mainly of clay particles which were once deposited on for example ocean floors (Arthur et al., 2008). The specific characteristics of the shale layer, such as permeability, grain size and pore space, are determined by the burial history of the shale (Boyer et al., 2006). Note that shale layers can serve as source rock for conventional oil and gas accumulations. Gas present in the shale layer can either reside in pores or small fractures present in the formation, be dissolved in fluid or be adhered to organic materials. As earlier mentioned, the conditions present in the formation and its burial history determine the presence and composition of hydrocarbons in the shale. For the United States most shale formations are at an depth of 1,5-4 kilometre (Arthur et al., 2008). In general, European shale formations will be somewhat smaller and deeper (Stevens, 2012)[6].

- Tight gas (or tight sand gas) is gas present in sand- or limestone formations. When looking at Figure 5 the gas migrated out of the gas rich shale layer normally accumulates beneath a caprock. However if the reservoir rock is not permeable enough, gas can accumulate in the tight sand formations. Tight gas accumulations are widespread and in the United States tight gas forms already 24% of the gas production gas production (EIA, 2013b). Tight gas accumulations are present up to depths of 4.5 km (Rogner et al., 2012).

[6] Shale formations in the Netherlands have an average depth between the 3-4 km. (Witteveen + Bos, 2013)

- Coalbed methane is gas formed during the transition of organic material to coal and can be, similar to shale, present in free or absorbed form in the formation. Coal layers are present at depths varying from 300-2000 metres and as opposed to tight or shale gas the gas is nearly always dry (Rogner et al., 2012). At the moment coalbed extraction is mostly limited to the United States where it makes up 9% of the total gas production (EIA, 2013e).

Other types of unconventional gas such as deep gas (gas in formations below depths of 4.5 km), aquifer gas (gas dissolved in ground water) and methane hydrates (gas preserved in crystal structure of water) are at the moment not economically attractive (Rogner et al., 2012). Although the potentials can be big (especially in the case of methane hydrates), it is often technically complex to extract them. Deep gas extraction has been tried in North America, Europe and Russia but seemed to be limited due to technical, safety and environmental limitations (Rogner et al., 2012). Since most formations contain at least a little methane, aquifer gas is widespread but concentrations are often low making production unattractive. Methane hydrates are also widespread and can be found in off shore basins around the world as well as in onshore basins in polar regions. Although the resource base by far exceeds the expected resources of other types of gas, most of these resources seem too low grade to become commercially viable anytime soon (Rogner et al., 2012). There are ongoing research programs in North America, Japan and India but so far commercial production has not been proven (Rogner et al., 2012).

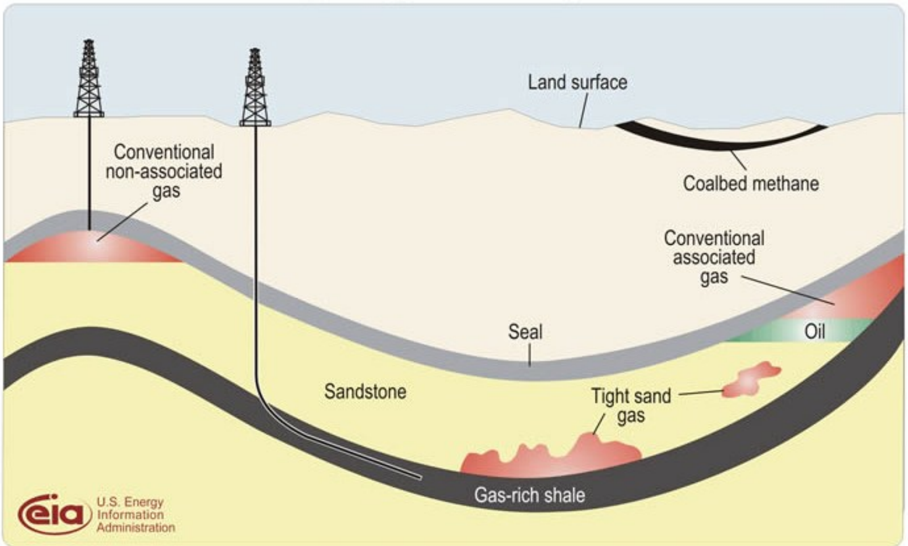

Figure 5 – Schematic geology of natural gas resources.. The temperature and pressure on the source rock depends whether gas, oil or both are produced. The source rock in this picture is the gas-rich shale, sandstone serves as the reservoir rock and the cap rock is depicted as the seal. (EIA, 2010)

2.2. Conventional versus unconventional gas production

In a conventional gas play the reservoir pressure itself is often sufficient to produce gas at commercial flowrates, although additional stimulation by injecting water or CO2 is can be used in later stages to minimize decline rates and maximize production. In theory one can tap a conventional gas accumulation by strategically drilling in the highest point of the reservoir, just as a bowl of water can be emptied by making a hole in its lowest point (Doust, 2011). Shale gas production differs from conventional natural gas production in the sense that is does not tap from the gas accumulated under the seal but from the source rock itself. The low permeability of the shale layer therefore inhibits the type of production applicable to conventional gas reservoirs since the gas would not be produced at a sufficient flow rate. In order to increase the permeability of the formation it has to be artificially fractured. The same goes for other types of unconventional gas present in low permeable reservoirs such as tight gas or coalbed methane. The combination of and advancements in two techniques made shale gas extraction profitable: horizontal drilling and fracking. Fracking can also be used in conventional reservoirs to boost production rates, although this will more often be in combination with vertical drilling which results in smaller scale of fracking since the surface area will be smaller (Montgomery, 2010). Figure 6 depicts a typical process diagram for shale gas developments, in the following sections the different aspects will be treated in more detail.

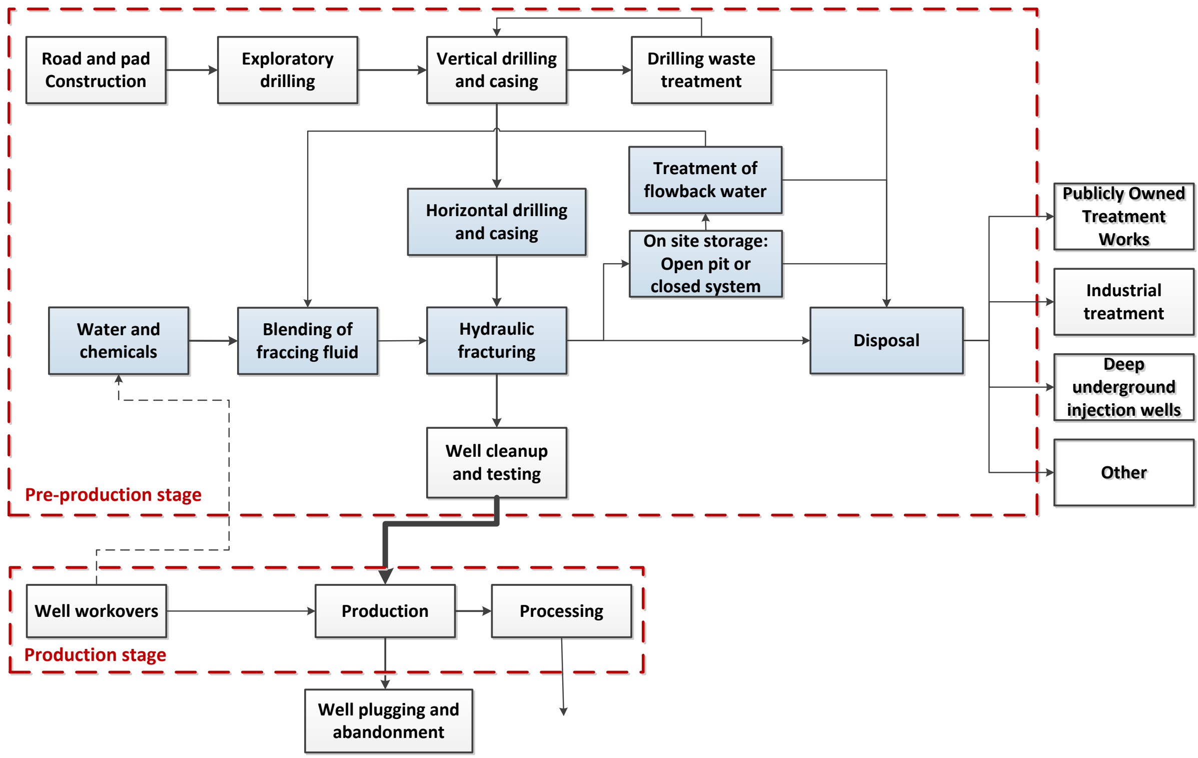

Figure 6 – Procesdiagram of gasproduction from exploration till processing. Blue-coloured boxes are typical for shale gas development, the of the depicted processes can also be expected during conventional gas production. Dotted arrows depict optional routes. Dotted squares represent commonly distinguished stages. (Adapted from: Louwen, 2009)

2.3. Vertical and horizontal drilling

First the vertical and horizontal shafts are drilled which are then cased with cement (see Figure 7). This cement casing is a measure to prevent leaking of water, chemicals and gas to the surrounding layers. Requirements to the applied type of casing is dependent on local regulations. In the U.S. regulations can vary per state, but typically multiple layers of casing are put in place in the first sections after which a single production casing extends to the bottom (Richardson et al, 2013). In the Netherlands, multiple layers are required to prevent leakage (Rijksoverheid, 2011). The drilling depth is dependent on the specific play, typical vertical depths range between 1,5-4 km and horizontal drilling can vary between several hundred meters up to several kilometres. Horizontal drilling is vital for shale plays since it enhances the area from which shale gas can be extracted. Directional or horizontal drilling can also be used to in conventional reservoirs, e.g. in order to penetrate the gas accumulation at the most advantageous point or to be able to place the drilling rig on a different location. For shale gas it is however more of a prerequisite in order to obtain commercial flowrates.

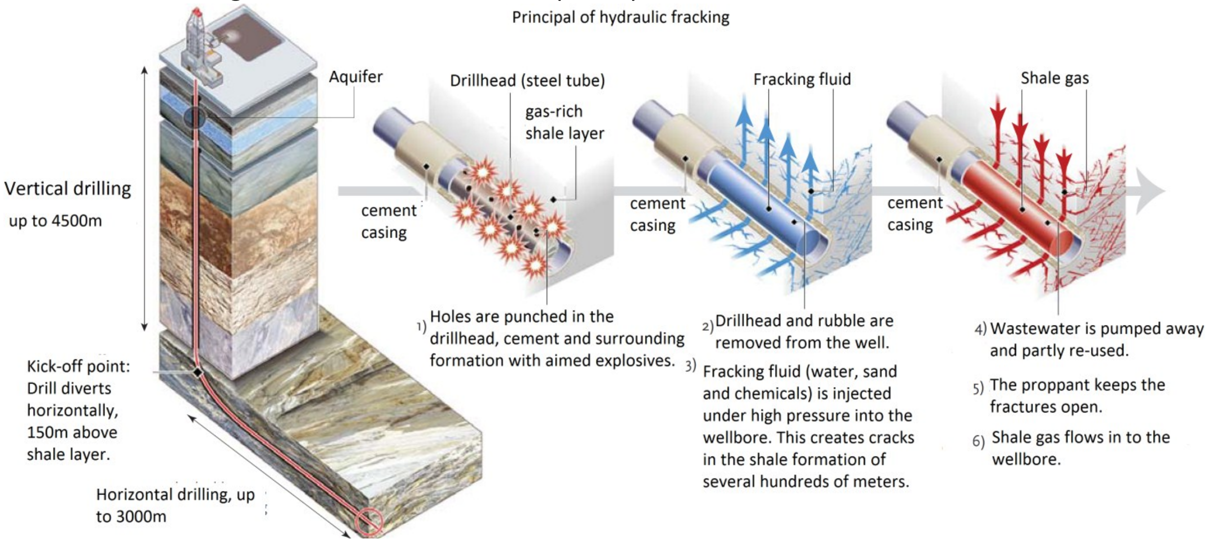

Figure 7 - Principal of hydraulic fracking. Drilling depth, casing and fracking fluid used are dependent on the specific play and local regulations. (Adapted from: TNO, 2012)

2.4. Fracking

In the horizontal part of the curve the cemented casing is perforated using explosives, upon which fracking fluid is injected under high pressure to fracture the shale layer. The basic functions of fracking fluids are: delivering sufficient energy to the formation to induce fractures, transport a proppant into the fractures to keep them open and form a permeable pathway (La Folette, 2010). Furthermore the fracking fluid should be easy to recover and be compatible with minerals and fluids present in the formation (LaFollette, 2010). Fracking fluid consists of three basic components: a base fluid, additives and a proppant. The base fluid usually consists of water, in some cases a compressed gas is added to the base fluid to aid in the recovery of the fracking fluid. The proppant often consists of fine-grained sand but also man-made proppants (e.g. ceramic grains) can be used. Additives are used for a wide-variety of purposes and their applicability depends on the specific play. Commonly used additives are used to reduce pipe friction in the injection stage, gelling-agents to increase the viscosity of the fracking fluid which enhances proppant transport, surfactants to aid recovery of the fracking fluid and biocides to prevent degradation of gelling agents and flowback fracking fluids. (LaFollette, 2010) The optimal mix of base fluid, additives and proppant is dependent on the specific play and local regulations. Water use in the fracking process varies, different estimates are in the range of 7,7-38 million of liters per well (Kargbo et al, 2010; Olmstead et al. 2013; Nicot & Scanlon, 2012). Typical fracking fluids consist for 90-95% of water (Kargbo et al., 2010).

2.5. Flowback water

Flowback water is recovered from the well and either re-used or disposed. Depending on the geological formation between 10-70% of the water is returned to the surface, either after the pressure is released at the end of the injection stage or during the time when the well is in production (EPA, 2012a).[7] Three basic pathways for flowback water disposal are currently applied in the US: discharge in deep underground injection wells, transport to publicly owned waste-treatment plants after which it can be discharged to surface waters or on site storage in either open evaporation pits or closed tanks (treatment can still be applied after that) ((Soeder & Kappel , 2009; EPA, 2012a). Flowback water can contain, next to the chemical additives, also brines, trace elements and naturally occurring radio-active particles which are present in the earth crust (Rahm et al., 2013).

2.6. Well in production

After the pre-production phases are completed the well can start producing. Since wide-scale shale gas development is a relative recent phenomenon, it is not quite clear for how long these wells will produce. Jiang et al. (2011) use a productive lifetime of 25 year in their analysis which is based upon leaked industry emails published in the New York Times.[8] The Joint Urban Studies Center (2008) also gives a 20-30 year production lifetime. Other analysts estimate the productive lifetime of shale gas wells much shorter at an average of 7-8 years, although it is mentioned that a significant part of the wells could produce for 12-15 years the amount of wells producing longer than 15 years is expected to be limited (Berman, 2009).

Initial production rates are typically 1582 GJ/day (Stephenson et al, 2011). Average expected ultimate recovery (EUR) per well is estimated at 2,1 PJ (Stephenson et al. 2011). For comparison, conventional natural gas wells in small fields in the Netherlands have an average EUR per well of 19-57 PJ (Herber & Jager, 2010). In cases of extremely good reservoir quality such as in the Groninger field this can stretch to an EUR of 268 PJ (Herber & Jager, 2010)[9]. EUR are however very location specific, in section 4.3 a more in depth analysis is given of the productivity of shale gas wells.

Most shale gas wells produce dry gas (90% or more pure methane). In addition some wells produce other hydrocarbons in an elevated concentration, but these are considered exceptions (Arthur et al, 2008). However due to low gas prices the industry has become more focussed on the portions of the shale gas plays which do produce natural gas liquids since they can be sold for higher prices (Hughes, 2013).

2.7. Technology development

Although shale gas extraction and fracking have been around for a long time, the technique has changed over the years which resulted in more efficient fracture treatments. Table 1 gives an overview of important technological developments. Technological milestones were the introduction of cross-linked gels whose viscosity can be influenced by changing the pH-value, this enabled a high viscosity during proppant transport and a low viscosity to increase the amount of flow back water. Improvements in seismic imaging have made it possible to more effectively place and evaluate hydraulic fracture treatments as well as enabling more precise drilling and thereby longer lateral lengths. The addition of friction reducers to the fracking fluid ('slickwater fracking') made it possible

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[7] Nicot et al. (2011) assumes 5-10% of the injected fracking fluid can be re-used in further exploration and exploitation drills. Jiang et al.(2011) estimates that 20% of the total water use during hydraulic fracking can be recycled.

[8] In the specific email conversation with a federal energy official a Chesapeake Energy geologist mentions his sceptical attitude towards this number due to the high decline rates in the first year of production. Several other emails also indicate more difficulties with respect to the recoverability and economics of shale gas than companies have been claiming. (Urbina, 2011)

[9] The Groninger field was up till 2010 produced with 296 wells with a cumulative production of ~79 EJ (2087 BCM) (Herber & Jager, 2010). This amount to an average EUR of 268 PJ/well (7 BCM).

to inject fracking fluids at a higher rate thereby increasing the amount of energy that can be delivered to the formation as well as increasing the amount of fracking fluid returning to the surface.

One of the methods increasingly used is called multi-well pad drilling. Pad drilling is a method wheremultiple wells are drilled from one site, reducing for example the land use, operating equipment and road building (Pickett, 2010). Furthermore technologies as coiled tube drilling are being used more and more (especially for well re-entries). Instead of using lots of conventional jointed steel pipes in the well bore through which the various substances are transported (drilling mud, cement, natural gas..) a flexible tube is used which is rolled of a spindle making sure the diameter of the well hole is reduced and drilling can be continued much faster. (Pickett, 2010). All these innovations have led to reductions in drilling time, increased initial flow rates and reductions in cost (Pickett, 2010; EPRINC, 2011).

In 2007 the average initial production rate was 1396 GJ/d, in 2010 this was already 3625 GJ/d. Average production rates of a well after thirty days were 1163 GJ/d in 2007 compared to 2724 GJ/d in 2010 (EPRINC, 2011). In this time the average horizontal length also doubled and the typical drilling time for a well was reduced from 30 days to 10 days (EPRINC, 2011).

Table 1 - Technological milestones in hydraulic fracture treatments. (New York State, 2009)

Time	Milestone
Pre-1900	Gasproduction from shale gas wells. Vertical wells fracked with foam.
1983	First gas well drilled in the Barnett Shale, Texas.
1980-1990's	Development and use of cross-linked gel fracking fluids in vertical wells.
1991	First horizontal well drilled in the Barnett Shale.
1991	Orientation of induced fractures indentified.
1996	Introduction of slickwater fracking fluids
1996	Micro seismic mapping of post-fracking situation.
1998	Slickwater refracking of gel fracked wells
2002	Multi-stage slickwater fracking of horizontal wells
2003	First hydraulic fracturing of the Marcellus Shale
2005	Increased focus on improving the recovery factor
2007	Introduction of multi-well pad cluster drilling

2.8. Refining

Natural gas extracted from the well often contains impurities which need to be removed in order to make the gas suitable for selling to the grid. These impurities can consist of acids, condensates, water, or other non-condensable substances. Based on their value and processibility these impurities are either disposed or sold. The exact composition of the raw gas stream is location dependent and can contain hundreds of different components (Mokhatab et al., 2006). Many different setups for a refining process therefore exist, some often found elements are depicted in Figure 8 - Schematic representation of a typical natural gas refining process. (Mokhatab et al., 2006).

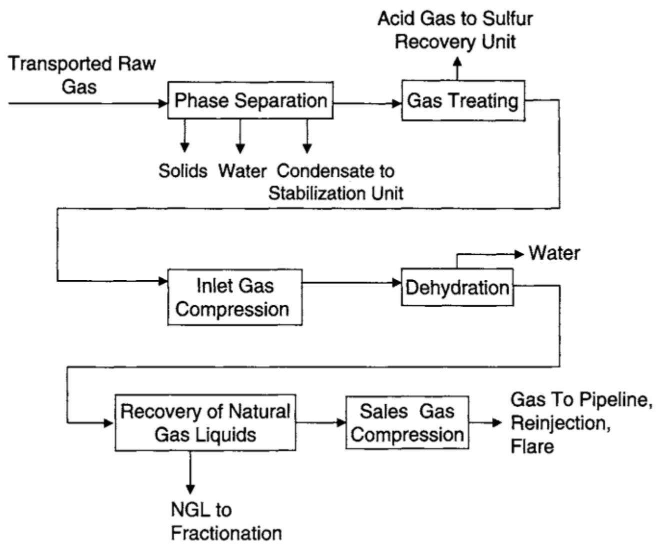


Figure 8 - Schematic representation of a typical natural gas refining process. (Mokhatab et al., 2006)

In the first stage the different phases present in the stream are separated, typically they consist of liquid hydrocarbons, liquid water and solids. Condensate hydrocarbons may be shipped directly or be subjected to further processing which often consists of removing additional dissolved methane or ethane. In the next stage acid gasses, formed by H_2S (and other sulphur containing compounds) and CO_2 can react with the water(vapour) present in the gas flow to form sulphuric acid and carbonic acid. The acids can cause corrosion and are removed for safety reasons. After that, the pressure is increased to a suitable level after which dehydration takes place. Under the right combination of temperature and pressure water and gas can form solid gas hydrates. These hydrates could lead to choking of the pipelines and therefore remaining water vapour in the gas stream needs to be removed. By cooling the gas further natural gas liquids condense after which they are either directly shipped or further processed. The natural gas is now ready for distribution after it is compressed to the appropriate pressure. (Mokhatab et al., 2006)

2.9. Distribution

2.9.1. Pipeline transport

Natural gas is often found far from the site of consumption and therefore large distances have to be passed. In general three types of pipeline can be distinguished: raw gas pipelines, interregional pipelines and distribution pipelines. The raw gas pipeline serves as a (relative small diameter and low pressure) connector between the wellhead and processing plant, if there is sulphur dissolved in the gas special anti-corrosion pipelines have to be used. Interregional pipelines are used to transport the processed gas over large distances to big end-markets and govern high pressures and bigger diameters. Distributional pipelines branch of the larger pipelines into an increasingly small network which is eventually connected to the individual homes. Compressors stations, a large number of valves and storage facilities allow regulation of the network and a balance between supply and demand. (Mokhatab et al., 2006) Pipelines do however have disadvantages. Pipelines can currently not be constructed deeper than 100 metres below sealevel and pipelines laid in water are more risky and costly compared to land pipelines. Next to that pipelines which have to be laid to multiple countries/states are subjected to pipeline politics and complicated regulatory frameworks which can make construction a costly and complicated process.

2.9.2. LNG transport

Gas can be liquefied to facilitate transport overseas or over large distances not connected by pipeline. In order to facilitate this transport the gas is cooled to -161 °C in specially constructed liquefaction plants, at which the energy density becomes 600 times greater which makes it suitable for transport by ship. On the receiving end the LNG is first loaded in to storage facilities after which it can re-enter the market via a regasification plant. LNG requires large capital investments, however so does pipeline transport. In general the industry holds a very rough rule of thumb stating that over distances of 3000-5000 km LNG transport becomes cheaper than pipeline transport. (Rogers, 2010)
In 2011 there were worldwide 60 regasification terminals spread over 20 countries, 50 more were proposed or under construction (Figure 9- World major LNG importing and exporting countries. (Kumar et al., 2011)). A total of 26 liquefaction plants spread over 17 different countries were globally in place in 2011 with another 30 proposed or under construction at the time. (Kumar et al., 2011)

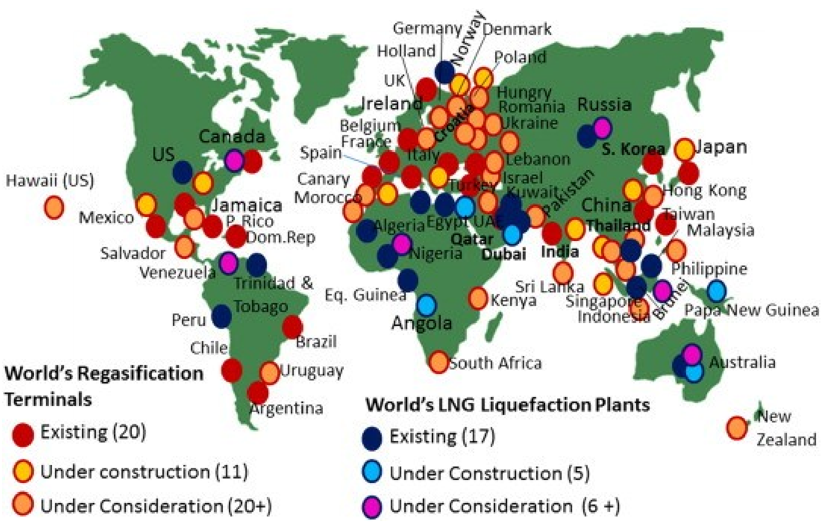


Figure 9- World major LNG importing and exporting countries. (Kumar et al., 2011)

3 Reserve and resource base

In this section an overview of different data sources with respect to reserve and resource estimates for natural gas will be provided. In addition, the cost of producing these resources will be discussed. In latter sections this will be connected to the TIMER model.

3.1 Classifications and definitions

There are several reserve and resource estimates which all have their specific scope and depth of analysis. Generally speaking, one has to deal with uncertainty, thus being forced to make several assumptions in order to be able to make a reserve or resource estimate. The part of the hydrocarbon resource base which eventually can be produced is dependent on several factors such as:

- Geology (How much is there? In what composition and with what probability? To what extent can we expect to find more resources in the future?)
- Technology (Does the necessary technology to extract the hydrocarbons already exist? Is it a proven or an experimental technology?)
- Economics (How much does it cost to produce the gas? What is the gas price?)
- Policy (Is the area where the hydrocarbons are located open for exploration? Under which conditions?)
- Time (On which timescale do I assess the probability of discovering more resource? To what extent can we expect technological progress? What will happen to the gas price?)

In order to deal with these uncertainties and assumptions, resource estimates are often categorized according to a system in which geological and economic factors are taken into account. Assumptions are however not always specified and there is little uniformity between different reporting agencies. This is a complicating matter when attempting to make direct comparisons between different numbers.

Definitions with respect to reserves and resource classifications in this thesis are based upon Rogner et al. (2012). Rogner et al. (2012) adopts the principle of a McKelvey Box (see Figure 10), a method of defining portions of the hydrocarbons present in the earth's crust along the two dimensions of probability of geological occurrence and techno-economic viability. Rogner adopted this scheme as well in an earlier assessment of global hydrocarbon reserves and resources (Rogner, 1997). A distinction is made between more general definitions used in overall speech and more in depth classifications used to allocate hydrocarbons to a specific category.

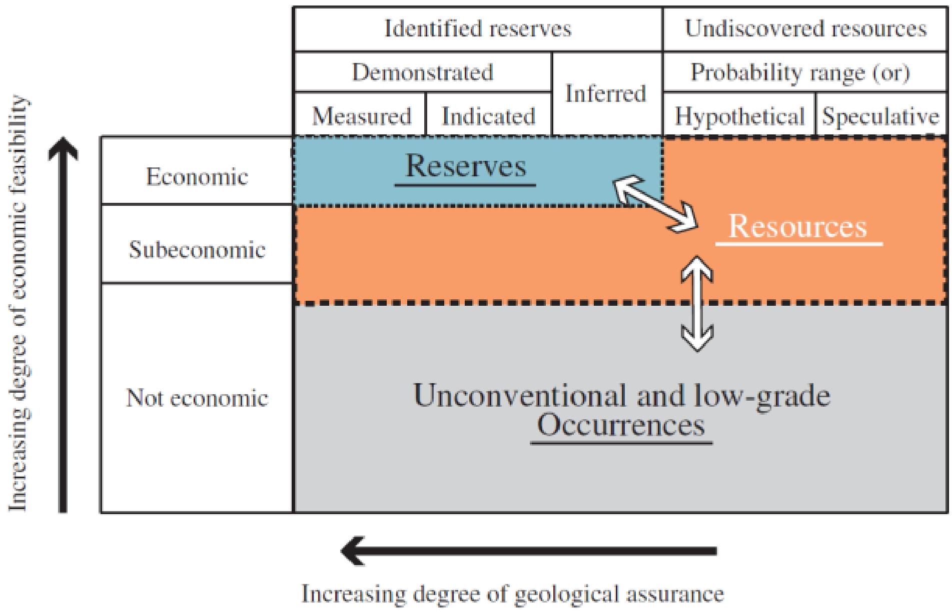


Figure 10 - Modified McKelvey Box as used by Rogner et al. (2012).

Generally speaking, reserves are considered to be the portion of the hydrocarbons present in the Earth's crusts for which geological and engineering information indicates with reasonable certainty that they can be recovered in the future from known reservoirs under existing economic and operating conditions (Rogner et al., 2012). Reserves can be further defined in measured, indicated and inferred reserves which indicate various degrees of certainty along the geological axis[10]. Resources are considered to be the portion of the hydrocarbons present in the Earth's crust in such a form that economic extraction is potentially feasible (Rogner et al., 2012). Note that resources stretch over identified and undiscovered resources, where (for identified resources) there is geological evidence pertaining the quality, quantity and location of the resource. Undiscovered resources are the portion of resources whose existence is suspected, based on analogous geological conditions (Rogner et al., 2012). Other occurrences consist of the portion of the hydrocarbon base which is considered too low-grade to be economically or technically extractable and consist for a large part of unconventional fuels (Rogner et al., 2012).

For more in depth allocation Rogner (1997) created eight categories along the axes of the McKelvey box. The same categories, together with some additional categories for modelling purposes, are used for the allocation of resources in the TIMER model, whereby successive categories have increasing production costs. A distinction is made between conventional (categories 1-4) and unconventional (categories 5-8) reserves and resources. Below are the definitions used to classify the resources. How these are implemented in the TIMER model is described in section 5.1.6. (Rogner, 1997; Mulders et al., 2006)

1. Proven recoverable reserves - Amount of oil or gas in known reservoirs that is available for future extraction under current and expected local economic conditions with existing technologies.

[10] In the oil- and gasindustry it is common practice to divide reserves in P1, P2 and P3 reserves which stand, respectively, for at least 90%, 50% or 10% probability of being recoverable under current circumstances with existing technologies (Rogner et al, 2012).

2. Estimated additional reserves – Amount of oil or gas which is, based on geological and technical information, expected to be found and to be recoverable. For this category the United States Geological Survey (USGS) gives an optimistic (95% probability of being at least the expected amount), best (50% probability of being at least the expected amount) and pessimistic estimate (5% probability of being at least the expected amount).

3. Additional speculative resources – in fact this coincides with category 2 but these are of a more specalutive nature. Rogner et al. (1997) uses the difference between the optimistic en median value, where the difference between the optimistic and best estimate is used in TIMER.

4. Enhanced Recovery – Additional oil and gas production from existing and abandoned reservoirs with advanced production techniques. For gas this category consists of 10% of the original in-situ amounts of conventional gas.

5. Unconventional recoverable reserves – Identified reserves of oil and gas that currently or in the near future can be produced against current international marketprices.

6. Unconventional resources – Comparable to category 2. In TIMER 20% of the expected recoverable resources are assigned to this category.

7. Additional unconventional resources – Comparable to category 6 but with an assignment of 35% of the expected recoverable resources.

8. Additional Occurences – Comparable to category 6 but with an assignment of 45% of the resources plus all the conventional and unconventional oil and gas which remains in-situ and cannot be extracted. Methane hydrates make up a large part of this category. Hydrocarbons in this category are not expected to be technically or economically recoverable before the end of the 21st century.

3.2 Uncertainty in reserve and resource data

Inherent uncertainties can be quite large, which can lead to large spreads in numbers. Although seismic technologies improved vastly over the past few decades, field complexity still makes accurate estimates of existing or prospective fields significantly more difficult. Seismic measurements can give an indication of the porosity and the permeability of a shale formation, which can be used to give a rough estimate of the amount of gas present in the formation. However, exploration drills are still necessary to give an indication of the actual presence of gas, the estimated recovery factor of the hydrocarbons and the potential economic viability (Zijp & Bergen, 2012). Exploration wells, however, cover only a small part of the formation, and formations are far from homogenous. Often they are curved plains extending over a range of depths which have experienced different burial histories over time. The nature of the shale gas resource, generally being spread out over a wide area instead of the strictly defined accumulations, makes the exploration risk quite low compared to conventional gas plays (MIT, 2011). However, the large variations and the unpredictability of a specific play due to heterogeneity can make the commercial viable successes volatile (MIT, 2011). This can be seen in the United States where the productivity of neighbouring wells can differ by a factor three, and even a factor ten difference in productivity within a formation is not uncommon (EIA, 2012e). Even the most intensive exploited shale formations in the United States have only been examined for 5% of the surface area, and outside the United States shale gas explorations are still limited (EIA, 2013d). A succinct quote in the context of the reserve estimation comes from energy researcher Robert L. Hirsch (2005):

"Reserve estimation is a bit like a blindfolded person trying to judge what the whole elephant looks like from touching it in a few places. It is not like counting cars in the parking lot where all the cars are in full view." - Robert L. Hirsch, 2005

Another factor leading to uncertainty in resource assessments are stakeholders who might have an interest in misreporting data in order to further their own political or corporate agenda[11] (Tsoskounoglou et al., 2008; SEC, 2004). Furthermore, there are some critical sounds from researchers, independent analysts and through industry leaks with respect to the estimates of shale gas reserves and resources and concerning the way reserve and resource estimates are currently formulated (Urbina, 2011; Berman, 2011; Herber &Jager, 2010). Seeing as a lot of data is classified and countries or companies not being too keen to share this information publicly, it is hard to check whether reported numbers match the actual situation. Some more in depth analysis on the critically acclaimed factors which could influence the reserve estimates can be found in section Productivity

3.3 Current natural gas reserve and resource data

The first comprehensive study containing global reserve and resource estimates for unconventional gas comes from Rogner (1997). This study was used in the TIMER model as an input for natural gas reserve and resource data. Rogner (1997) had to deal with severe data limitations in his reserves and resource estimates due to little commercial interest at that time. In the case of shale gas he took the properties of a United States shale formation and extrapolated this data to the amount of shale formations in the rest of the world (Rogner, 1997). When hydrocarbon reserve and resource data was updated in TIMER by Mulders et al. (2006), a new USGS (2000) study was performed which estimated the conventional reserves and resources. For unconventional gas however, the new data was still extremely limited and therefore the current unconventional gas estimates in TIMER are still based upon the Rogner (1997) estimates (Mulders et al., 2006). After shale gas exploitation took off in the United States mere academic curiosity in shale gas reserve and resource data made place for more commercial interest which resulted in increased data with respect to shale gas reserves and resources. In 2011, the EIA published an assessment of major shale gas basins located in 32 countries outside the United States, regarding basins on which sufficient geological data was available and which showed some short term promise of the possibility of extraction (EIA, 2011). This was updated in 2013 to a total of 41 countries (EIA, 2013d). The resulting map is shown below, which gives an indication of the geographical distribution of the world's shale resources (see Figure 11). Other authors and institutions have also made estimates of shale gas resources. Rogner et al. (2012) has provided a new global estimate with a reserve and resource potential for unconventional gas with a long timeframe (reserves and resources which could be potentially extracted before the end of the 21st century). The IEA has also made several assessments based upon EIA estimates and its own sources in addition to other literature (IEA, 2011; 2012). Several separate assessments have been made for the Netherlands (TNO/EBN, 2009; TNO, 2012; Herber & Jager, 2010). In general, current reserve and resource assessments with respect to shale gas do not account for economic or location-specific circumstances and it is very well possible that in later stages considerable revisions will be made (some of the revisions can already be seen in Table 2. Table 3 compares the unconventional gas estimates (not only shale gas) in TIMER with more recent estimates by Rogner et al. (2012) according to the McKelvey box classifications (see Figure 10).

[11] Examples of misreporting of reserve data are the overstatement of oil reserves by Shell in 2004 which led to the American Securities and Exchange Committee (SEC) forcing the company to pay a 120 million dollar fine for overstating its oil reserves by 23% (SEC, 2004). In addition, the introduction of production quota for OPEC members during the 1980's led to a sudden increase of 47% of the OPEC reserves in the period 1985-1988, which led to a lot of criticism by experts (Tsoskounoglou et al., 2008).

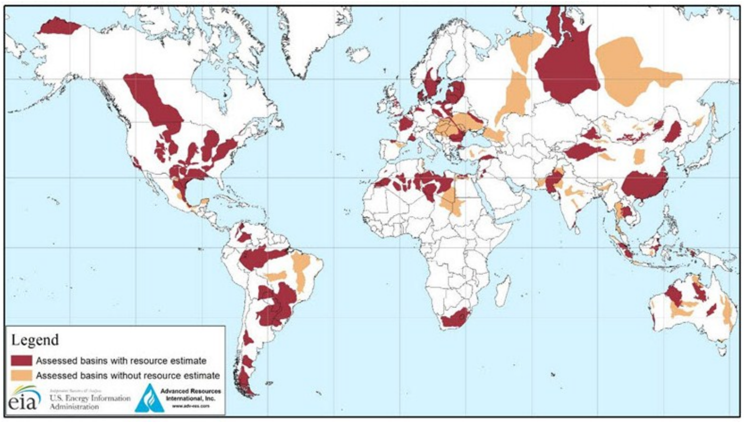


Figure 11 - Distribution of the world shale gas basins in 41 assessed countries. Red colored areas are shale formations for which a resource estimate is given, orange colored estimates are shale basins which were assessed but for which no resource estimate was given due to a lack of geological data and white areas were not assessed (EIA, 2013d).

Table 2 – Various global and regional shale gas resource estimates in EJ. Different definitions are used by the various authors, definitions offered by the authors are included.

Shale gas resources [EJ]	World	Europe	NL	VS	Note
Rogner (1997)	17208	586	-	4103	Gas Initially In Place (GIIP) (All hydrocarbons in the reservoir)
TNO/EBN (2009)	-	-	211-4899	-	Producible Gas In Place (PGIP), best estimate. PGIP = GIIP x recovery factor (5%)
Herber & Jager (2010)	-	-	0.38-0.75	-	Potentially recoverable volume*
EIA (2011)	7198	614	18	937	TRR**, 32 countries assessed.
EIA (2013)	7632	511	28	616	TRR**, wet gas. 41 countries assessed.
IEA (2011)	7831	614	-	2111	TRR**, OECD Europe.
IEA (2012)	7677	614	-	1804	TRR**, OECD Europa.
Rogner et al. (2012)	6296	448	-	1863	Reserves ***
	14903	1118	-	4098	Resource potential ****
Zijp (TNO) (2012)	-	-	7.54 - 18.84	-	TRR*
Gasconsumption over 2012 in EJ (IEA, 2013)	133,1	19,6	1,53	27,5	OECD-Europe

* Recovery factor included, exclusion of areas not suitable for gas production (e.g crowded area's) or parts of the formation which will probably not produce economically.

** Technically Recoverable Resources (TRR). Recoverable with current technologies, economic aspects excluded. Comparable with producible gas in place but with an extra factor included accounting for geological knowledge about producible parts of the shale formation.

*** P1, P2 and P3 reserves (see footnote 10).

**** Hydrocarbons in the earth's crust in such a form that extraction is potentially economically feasible.

Table 3 - Resource estimates currently used in TIMER (last update by Mulders et al., 2006) compared to more recent estimates by Rogner et al. (2012). Range for theoretical potential of methane hydrates is displayed for Rogner. Circum-arctic included in the Rogner et al (2012) estimate for conventional resources. Methane hydrates are displayed separately due to their vast size and speculative nature. Since Rogner et al. (2012) does not present his data into different categories (only in reserve and resource format) TIMER categories are aggregated (category numeration according to Rogner (1997), see Table 10). In the TIMER estimates the recovery factor is incorporated. (Rogner, 1997; Mulders et al., 2006; Rogner et al., 2012).

Global recoverable gas resources [EJ]		**Mulders et al. (2006)**	**Rogner et al. (2012)**
Conventional gas	Reserves (cat. 1)	5851	5021
	Resources (cat. 2-4)	6858	7193
Unconventional gas	Reserves (cat. 5)	5652	20 156
	Resources (cat. 6-7)	20903	40 275
	Methane hydrates (cat. 8)	475 458	2496 - 2 772 889

3.4 Supply cost curves

As mentioned before, factors such as depth, thickness, size and composition can vary heavily between gas resources. Consequently, this will also lead to large variations in extraction costs between different gas plays (Weijermars, 2013). When gas reserves are ranked in order of increasing extraction cost, a supply cost curve emerges (de Vries, 2013). A supply cost curve displays the marginal cost of producing a part of the resource base. Depletion of the resource base will therefore lead to higher production cost as the easy accessible, cheap resources run out. Technological progress on the other hand will have a downward effect on the production cost. As new technologies are developed or existing technologies mature, the cost of producing a certain part of the resource base may decrease.

Due to uncertainties with respect to reserve and resource data (section 3.2) and uncertainties with respect to estimating the production cost of yet to be developed resources, supply cost curves can show considerable discrepancies. Figure 12 depicts several global supply cost curves for natural gas. Conventional resources are estimated to amount to around 12 000 EJ (see Table 3) (Rogner et al., 2012). The MIT (2011) curve excludes unconventional gas outside the United States, which explains the steep rise between the 10 000 and 15 000 EJ mark. Rogner et al. (2012) includes 12 000 EJ of conventional gas next to 28 000 EJ of unconventional gas in the curve. The 28 000 EJ of unconventional gas consists of the unconventional gas reserves, 20% of the unconventional gas resources and 5000 EJ of methane hydrates. TIMER includes 12 700 EJ of conventional gas next to 26 555 EJ of unconventional gas reserves and resources. Furthermore, 475 458 EJ (methane hydrates) of additional occurrences are included in the TIMER supply cost curve, which are omittedfrom Figure 12 since they would distort the picture too much.

The TIMER and Rogner et al. (2012) curve displays the production cost without technological learning, royalties, taxes or profit margins. MIT (2011) does assume some royalties and taxes in their supply cost curve, although the assumed amounts are not separately specified.

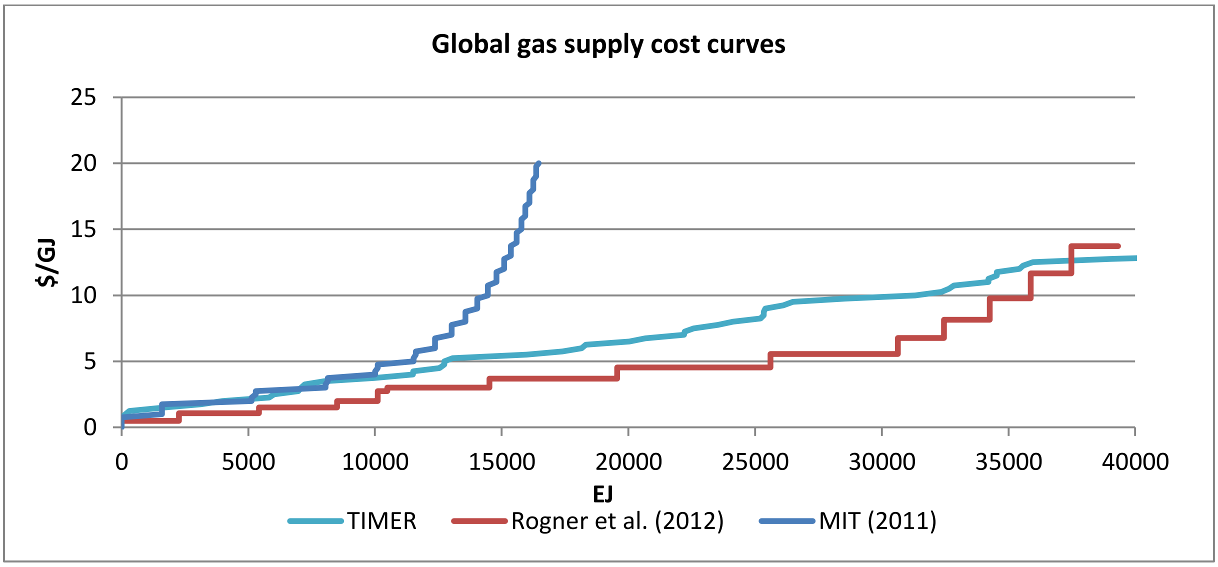


Figure 12 - Global long-term natural gas supply cost curves from various sources, including the supply cost curve from the original TIMER model. The curves are based solely on depletion dynamics, no technological progress is assumed. (Rogner et al., 2012; MIT, 2011)

The curve from Rogner et al. (2012) shows that around 5000 EJ can be produced for around 1$/GJ or less, which translates to almost 40 years of global gas consumption according to the current consumption rate. Conventional gas in the Rogner et al. (2012) supply cost curve has a cost range of 0.50-3.50 $/GJ. Unconventional resources differ more regarding the required extraction technology and they therefore cover a broader price range. Shale gas from very permeable reservoirs, on shore gas hydrates or coal bed methane starts as low as 2$/GJ. In comparison, the highest production cost are assigned to offshore deep gas reservoirs and amount up to 13 $/GJ. The TIMER and MIT (2011) curve are slightly higher in their cost for conventional gas. For the MIT curve, the inclusion of taxes and royalties in the production cost could play a role. For the TIMER curve, it is probably due to differences in cost estimation. Especially with respect to unconventional gas resources, the Rogner et al. (2012) supply cost curve seems to deviate from the TIMER supply cost curve. Since the range of unconventionals start at 2 $/GJ, the cheapest 8000 EJ of the resource base consist of conventional gas. This indicates that on a aggregated global scale from a pure economic perspective conventional gas will be preferred over shale gas. Concerns pertaining energy security and regional deviations could,however, still lead to short term shale gas development.[12]

When looking at some regional gas supply cost curves it becomes apparent that (especially for the USA) large deviations are present with respect to unconventional gas in the TIMER and Rogner et al. (2012) supply cost curve (see Figure 13). Conventional gas included in the USA curve amounts to ~700 EJ, followed by unconventional gas dominating the supply cost curve (Rogner et al., 2012). The Former Soviet Union (FSU) holds the biggest conventional gas reserves and unconventional gas reserves in the world, which explains the low supply cost within this region. Conventional gas supplies in the FSU amount to 1600 EJ (Rogner et al., 2012). Furthermore, the supply cost curves of Rogner et al. (2012) seem to suggest for Western Europe and Eastern Europe that more gas can be supplied at lower prices than currently incorporated in TIMER. Conventional gas supplies amount to 657 EJ for Western Europe and 41 EJ for Eastern Europe. As production costs come close to 30$/GJ,

[12] Current annual gas consumption ≈ 133 EJ (see section 1.2), RPR before shale gas becomes preferred fuel on an globally aggregated scale is around 70 years. However, growing energy demand will change this picture.

methane hydrates become available in TIMER, they are however excluded from the graph for visibility. For a complete overview of regional supply cost curves refer to Appendix D. Supply Cost Curves

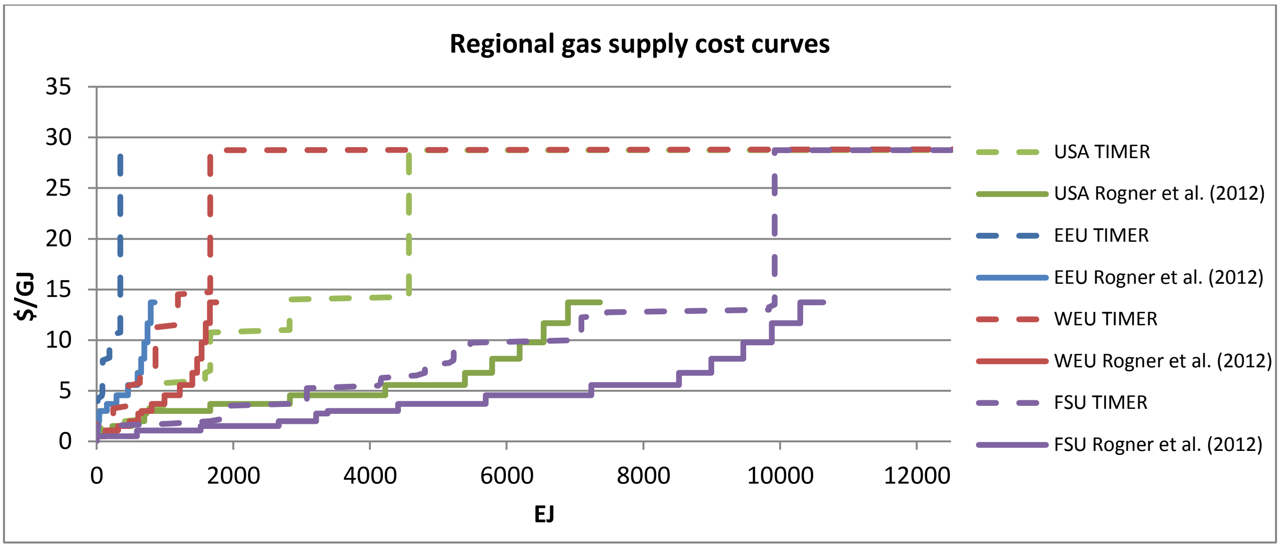


Figure 13- Regional natural gas supply cost curves in TIMER compared to Rogner et al. (2012). USA= United States, EEU = Eastern Europe, WEU = Western Europe, FSU= Former Soviet Union. (TIMER; Rogner et al., 2012)

It is of importance to note that the viability of a shale gas play is also heavily correlated to the amount of condensate produced along with it. If the oil price is high and the gas price is low, it becomes attractive to produce so called wet gas. The oversupply of gas in the US market led to an oversupply of gas and low prices; as a result a switch to the production of wet shale gas wells was seen.[13] In later sections this will be discussed in more detail. The correlation between the ratio of condensate present per amount of gas produced and he resulting breakeven price is shown in Figure 14.

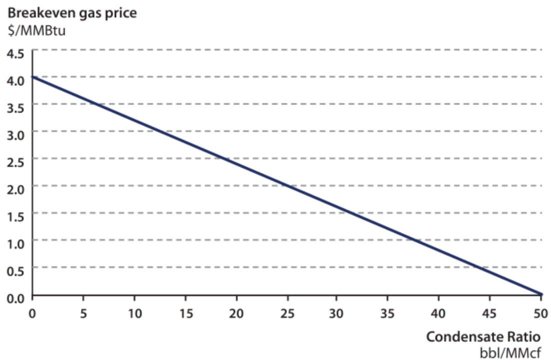


Figure 14 - Breakeven price of gas with varying condensate ratio's for a mean performing 2009 Marcellus well assuming a liquid price of 80$/bbl. (MIT, 2011)

[13] When condensates are produced, natural gas is produced as well. A switch to wet shale gas wells therefore does not necessarily reduce the amount of gas becoming available to the market.

4 Enviromental considerations

4.1 Fracking

4.1.1 Water use and management

An often mentioned disadvantage of shale gas development, and hydraulic fracturing in particular, is the amount of water required, as well as the management of wastewater streams. A distinction can be made between issues surrounding the water quantity used and issues regarding the effects on water quality. Water-use and management can be divided between three separate stages in the development and the lifetime of a well: the drilling, the hydraulic (re-)fracturing and the resulting flowback/produced water during the lifetime of a well. Water use per well can vary significantly: a literature survey suggest a variation between 7-38 million litres per well (Kargbo et al, 2010; Olmstead et al. 2013; Nicot & Scanlon, 2012). The variation of water consumption per well can be attributed to inter-well differences in four areas: geological (maturity of the shale and formation thickness); technological (horizontal vs vertical wells, water recycling, drilling techniques used); operational (proximity of fresh-water source) and regulatory (Bené & Harden, 2007). Average water use per well seems to be in the order of 10-20 million litres, depending on the specific shale (US DOE, 2009; Nicot & Scanlon, 2012). Table 4 gives an overview of estimates water use in the pre-production stage.

As the methods of the shale gas industry develop, improvements are seen in reduction of the amount of water used and in the treatment of the flowback water (US DOE, 2009). Although the withdrawal of large amounts water in a short time period for hydraulic fracturing can lead to temporary stresses on the water supply, the water intensity per unit of electricity is small compared to other fossil fuels (see Table 5)[14]. Most of the water use in the full cycle of the production of fossil fuels can be attributed to the cooling necessary during combustion. The relatively high efficiency of NGCC's ensures a low water intensity (Grubert & Kitasei, 2011; Cooley & Donnely, 2012). However, it should be noted that not every type of water use is comparable. Water used in cooling towers will, for example, not be polluted with chemicals and can often directly be discharged to the environment. In the following sections the water use during shale gas operations will be explained in greater detail.

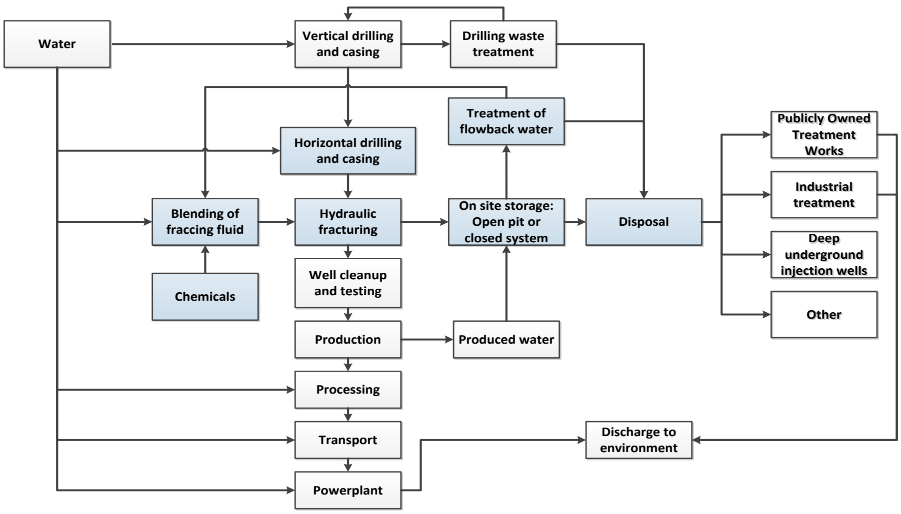


Figure 15 - Schematic overview of water use during the life cycle of natural gas. Blue boxes indicate stages typical for shale gas development. (Adapted from: Louwen, 2009)

[14] Note that, with an assumed EUR of 2 BCF (2172 TJ or ~604 GWh)and a NGCC power plant efficiency of 45%, the water use in Table 4 is comparable to the water use in the extraction phase of Table 5 → 36-55 L/MWh.

Table 4 - Water consumption during shale gas development in the pre-production stage. (US DOE, 2009; Chesapeake Energy, 2012; Nicot et al., 2011)

Water consumption in megaliter/well	Barnett	Marcellus	Haynesville
Drilling (average value)			
US DOE (2009)	1.5	0.3	3.7
Chesapeake energy (2012)	0.95	0.38	2.3
Fracking (median value)			
Nicot et al. (2011)	9.8	-	18.7

Table 5 – Water intensity of coal, conventional natural gas and shale gas. (Grubert & Kitasei, 2011)

Waterconsumption (litres/MWh)	Coal	Conv. Gas	Shale Gas
Extraction	11-53	neglible	29.4
Processing	0-109	57.5	57.5
Transport	neglible	28.8	28.8
Cooling	1970-3940	490-1900	490-1900
Total	1981-4102	576,3-1986,3	604,5-2015,7

4.1.2 Drilling

Fluids used in the drilling process serve several purposes: lubrication, cooling and extracting. By injecting a fluid during the drilling process, a circular mud flow arises which brings up the excavated parts of rock while simultaneously cooling the drilling bit. Various types of drilling mud are used: compressed air (mixtures), water-based muds and oil-based muds. Water-based muds are most common in oil and gas drillings, but within the shale gas industry the alternatives are somewhat more popular in comparison with conventional gas operations (Nicot et al, 2011). The drilling technique used is dependent on the hardness and the depth of the shale as well as operator preference. In more shallow plays, air mixtures may suffice, but drills over extended lengths are typically oil- or water-based. The actual water use of the drilling process is hard to establish since operators are not required to report this water consumption (Nicot & Scanlon, 2012) Next to that variations in water-consumption per operator and per play make it unreliable to extrapolate data from one source.

The US DOE (2009) estimated an average water use of 1,5 million litres to 3,7 million litres for drilling a well in respectively the Barnett and Haynesville shale. These wells were drilled using a water-based drilling mud. Chesapeake energy (2012), a shale gas operator, estimated drilling water use at 0,95 million litres for the Barnett and 2,3 million litres for the Haynesville shale, which is lower than the US DOE estimates. In the Marcellus and Fayette shale, different types of drilling muds were used, leading to a lower value for the water use (US DOE, 2009). The US DOE (2009) estimates an average of 227 000 litres and 303 000 litres were required for drilling at the Fayette and the Marcellus shale, respectively. Chesapeake Energy (2012) estimates water use at 379 000 litres per well for the Marcellus shale. On the surface the fluid and solids present in the drilling fluid are separated, after which the drill cuttings are disposed of as solid waste and the fluids are either re-used or also disposed (NYS WRI, 2012).

4.1.3 Hydraulic Fracturing

Hydraulic fracturing, or fracking, is used in a wide range of processes: geothermal energy, water well production enhancement, conventional oil and gas development and unconventional oil and gas development. It is estimated that a total of 2,5 million hydraulic fracture treatments have been performed since its introduction in 1949 and that 60% of the wells drilled today are fractured (this includes conventional oil and gas wells). (Montgomery & Smith, 2010). Although the process of fracking has been used for quite some time now, the specifics and the scale have changed over time (see section 2.7). Shale gas formations are often fracked over long lateral lengths with multiple fracking stages (multistage hydraulic high volume slickwater fracking), whereas conventional fracking often happens over a vertical, much shorter, range Fracking of conventional wells only uses 1-2% of the water compared to the fracking of shale gas wells (Howarth et al, 2011). Over the lifetime of the wells, additional fracking may occur to further stimulate the well, which may happen ten times or more(Montgomery & Smith, 2010). The amount of water used in the fracturing job varies (similar to the situation with drilling), with the specific geological, technical, operational and regulatory variables in place. In literature, a range of <1-49,2 million litres per well can be found (EPA, 2012; Beauduy,2011; Nicot et al., 2011). Table 4 - Water consumption during shale gas development in the pre-production stage. (US DOE, 2009; Chesapeake Energy, 2012; Nicot et al., 2011)gives values for the several shale gas formations.

4.1.4 Wastewater

Wastewater of shalegas can be divided into three distinct pathways: drilling mud (see section Drilling), flowback wastewater coming from the well in the period between the hydraulic fracturing and the start of actual production and produced brine which is water flowing to the surface during the operating lifetime of a well (Rahm et al., 2013). The drilling muds are a small part of the wastewater stream, as flowback rates of hydraulic fracturing fluids are between 20-80% and wells produce 1-2 m^3/day of brine during their lifetime (Groat & Grimshaw, 2012). One should keep in mind that it is impossible to distinguish between produced water from the formation and injected water during the flow back of the water/brine: numbers regarding the return of injected water to the surface are therefore somewhat arbitrary (Cooley & Donnely, 2012). Ratios of water ultimately produced to volume of fluid injected are location-dependent and vary between 0.15-3.1. The reasons for these large fluctuations are not well understood (Groat & Grimshaw, 2012)[15]. Water that does not return to the surface stays bound to the formation matrix.

Water returning to the surface contains, in addition to the chemicals present in the fracturing fluid, a lot of dissolved solids present in the geological formation. In general, a lot of salt is dissolved, as well as metals and Naturally-Occuring Radioactive Materials (NORM). The Total Dissolved Solids (TDS) levels, an aesthetic indicator for water quality, can be as high as >100,000 mg/L (Rahm et al, 2013)[16]. Haluszczak et al. (2013) showed that flow back water from the Marcellus shale contained levels of radium^{226}, radium^{228}, barium and other constituents which significantly exceeded the maximum allowed concentration levels for drinking water (13-1300 times for Ra), for which reason they could be a threat if discharged to surface waters. Furthermore, the presence of arsenic, benzene and other volatile organic compounds (VOC's) in the flow back water, originating in the fracturing fluid, is an additional matter of concern. Little research has been conducted, however, on the effects of the shale gas industry on public health. One should keep in mind that produced brine, being flow back in later stages, does not differ in chemical composition from produced brine in conventional oil and gas operations (Haluszczak et al., 2013).

[15] Barnett 3.1; Haynesville 0.9; Fayetteville 0.25; Marcellus 0.15

[16] TDS-levels do not specifically describe the toxicity of the water, they describe the amount of organic and inorganic content dissolved in the water. TDS-levels are often used as an indicator to determine the need for further investigations into the water quality. A test panel study by the World Health Organization(WHO) showed that water with TDS levels above 1200 mg/L is considered unacceptable by most people (WHO, 2003). Seawater has a TDS level of 35000 mg/L. (Cooley & Donnely, 2012)

Ideally, the flow back water/produced brine could be used again in the fracking process; this leads, however, to corrosion issues, clogging of the well[17] and decreased performance of chemicals mixed within the water (Bené & Harden, 2007). Since the nature of the water does not allow for immediate discharge or re-use, the water must be treated first. The flow back water is first stored in open pits or tanks, after which it is transported (by truck or by pipeline) to a treatment facility. Several pathways exist namely industrial treatment facilities, public owned treatment works (POTW's), on-site treatment or injection into underground wells (Rahm et al., 2013). Regulations in the US regarding wastewater management vary per state and, due to the recent debates, regulations are being revised in a lot of states. For example, the discharge to POTW's is allowed in some states, prohibited in others, and some states require pre-treatment before discharge to a POTW (Groat & Grimshaw, 2012). The same goes for open pit storage, which might overflow or leak. It is for this reason that closed systems with storage tanks are often the preferred choice from an environmental point of view. However, not all states have policies in place which require closed systems.

Most wastewater is injected in underground injection wells for long-term storage (Gregory et al., 2011). In certain areas, however, the capacity available is limited. For example, around the Barnett shale in Texas, around 11,000 wells are available but only 7 suitable wells are available near the Marcellus shale (Gregory et al., 2011). Consequently, main practices for wastewater management differ per region. Moreover, practices change over time due to improved technologies and increasingly stringent regulations. For the Marcellus shale region, the amount of water that is re-used over time has increased dramatically, at the expense of disposal at POTW's (see Figure 16)[18]. The use of POTW's has decreased due to public scrutiny and the limited capacity of POTW's to deal with high levels of TDS (Rahms et al. 2013; Gregory et al., 2011). Furthermore, re-use is preferred because it diminishes water consumption and its associated problems, in addition to lacking the disposal- and transport costs of water.

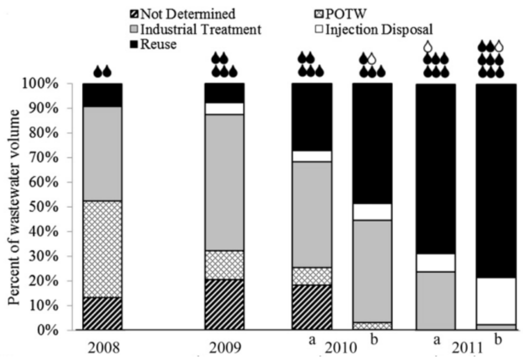


Figure 16 - Wastewater management trends for Marcellus operations across Pennsylvania for each reporting period. More stringent policies required six month reporting from 2010 onwards, hence a and b. Wastewater volumes are indicated above the bars: closed drop=200 000 m^3, open drop=100 000 m^3. (Rahms et al, 2013) (see footnote 18)

[17] The use of salt water increases the potential for higher deposits of scaling within the well bore hole, formation and surface equipment. This can impede the gas flow (Bené & Harden, 2007).

[18] Water that is re-used is often first industrially treated, but this was not accounted for in the database used by Rahms et al. (2013). The percentage which is industrially treated is therefore higher than represented in the graph. Apart from pre-treatment in an industrial plant, the wastewater is blended in some cases with fresh water to reduce TDS levels.

4.1.5 Chemicals used

The large majority of the fluids injected during hydraulic fracturing is water Average values are around 95-99%, depending on the well specifics. However, due to the large volumes of fracking fluid used there is still a considerable amount of chemicals injected, up to several hundred-thousands of litres. Due to the “Halliburton Loophole”, fracking was exempted from the Emergency Planning and Community Right to Know Act. This meant that companies were not obliged to disclose information pertaining the chemicals they were using, reasoning that it is a trade-secret which could give companies a competitive edge. In 2010, the Fracturing Responsibility and Awareness of Chemicals Act was proposed which would counteract the loophole, although it has not been accepted to this day. Fears of migration of these chemicals to drinking water aquifers, further fuelled by the secrecy of companies surrounding the specific chemicals used, led to an on-going debate on hydraulic fracturing. Some states reacted with laws which forced companies to disclose the chemicals used and some companies voluntarily disclosed the information in an attempt to calm tensions. Although understanding has improved, there is still not a clear picture about the injected concentrations of key-chemicals and the environmental risks they could impose (Groat & Grimshaw, 2012).

In a survey held by a congressional committee in the U.S., 14 oil and gas companies were asked to disclose information about the additives used in their fracturing operations between 2005 and 2009. A total of 750 chemicals and other constituents were found in a variety of 2500 products used (Waxman et al., 2011)[19]. The specific mix used differed per formation and could range from simple mixes only containing water and sand to more complex mixes using multiple chemicals. A lot of the 750 chemicals serve similar purposes along which an operator or service company chooses the most suitable.

Common purposes for chemicals in fracking fluids consist of (Groat & Grimshaw, 2012; Kaufman et al., 2008; Broderick et al., 2011):

- Friction reducers: reduce friction to enhance injection and flow back rates.
- Biocides: to kill bacteria which produce hydrogensulfate, which causes corrosion, and to prevent biofouling of fractures.
- Gelling agents: to influence the viscosity of the fluid and enhance proppant transport/placement.
- Corrosion agents: to prevent corrosion and degradation of the wellbore.
- Scaling agents: to prevent clogging of the well.
- Acids: to enhance fracture inducement.
- Surfactants: to reduce surface tension and thereby enhance flow back rates.
- Breakers: to break down other additives which can cause formation damage.
- Clay stabilizers: to prevent clay particles from swelling or dissolve/immobilize them as they can cause formation damage.
- Iron control: to prevent well clogging due to precipitating metal oxides.
- Cross-linker: increases viscosity of the fracking fluid to carry more proppant.

The website FracFocus, an initiative of the Ground Water Protection Council and Interstate Oil and Gas Compact Commission to gather information about chemical disclosure by companies, has compiled an inventory of the average hydraulic fracturing composition used in U.S. shale plays (see Figure 17).

[19] A product in this context is a certain composition sold by service companies who provide the fracking fluid.

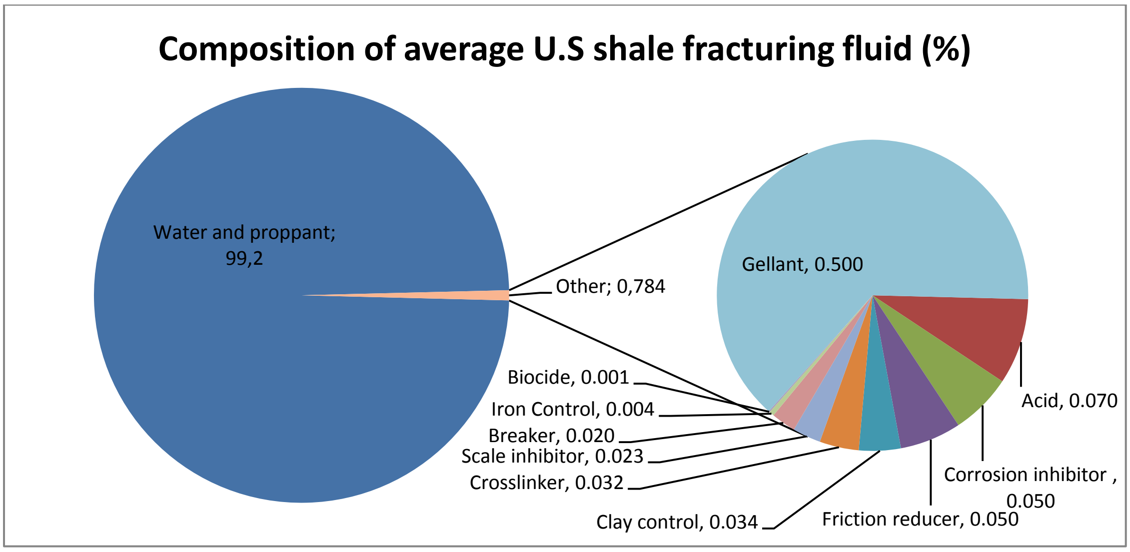


Figure 17 –Composition of average U.S shale fracturing fluid. (FracFocus, 2012)

Of the 750 different additives there were 29 chemicals which were either known or possible carcinogens, regulated under the Safe Drinking Water Act as a risk for human health or listed as hazardous air pollutants under the Clean Air Act (Waxman et al., 2011). Of the total of 2500 fracking products examined by the committee, 658 contained one or more of these chemicals. Since little is known about the used concentrations, it is unclear to what extent these chemicals produce a health risk, although the nature of the fracking fluid certifies as a potential danger. Since many of the chemicals used in the fracking process are also used in consumer products or are otherwise introduced to society through to emissions from e.g. transportation or electricity generation, it is hard to attribute health problems specifically to the shale gas industry (Groat & Grimshaw, 2011).

4.1.6 Risk of spills/leaks

Due to the "Halliburton Loophole" there was no obligation for operators to make an environmental impact assessment before operations started. This led to the fact that very few baselines exists which increases the difficulty of making an assessment of the damage shale gas operations may have caused environment (Stevens, 2012). Meanwhile, more stories, (perhaps most famously the documentary Gasland) of flaming faucets, contaminated rivers and water wells came out near shale gas operations. Critics of the documentary mentioned the possibility of biogenic gas produced by microbes present in the water which could be responsible for the presence of gas in the water supply. Most stories have mere anecdotal evidence but some academic studies do exist, primarily focussing on the Marcellus shale. Water contamination occurs in various forms: gaseous (methane), liquid (fracturing fluids) and solid (drill cuttings) (Rozell & Reaven, 2011). Chemicals may end up in the environment by improper waste water management, compromised well integrity, upward migration through the formation and spills on the surface during transport or on-site handling and storage (Rozell & Reaven, 2011).

In Osborn et al. (2011), a widely cited study, 68 private water wells (36-192 m deep) were analysed for a variety of substances (e.g. dissolved salts and dissolved constituents of boron and radium)[20]. In addition, 60 wells were analysed for the presence of dissolved gasses (methane and higher hydrocarbons). Osborn et al. distinguished between wells located in the vicinity of active gas extraction areas (<1 km) and areas further removed from these gas extraction areas (>1 km). Although no signs of contamination of water wells by brines or fracturing fluids were found, wells located near active gas extraction sites contained higher methane concentrations (see Figure 19). Isotope readings and ratios of methane-to-higher hydrocarbons (ethane, butane etc.) of wells near active extraction sites corresponded with gas found in the deep shale layers, indicating the methane migrated. Although most examined wells contained methane, wells located further away from active drilling areas tended to contain more biogenic methane.

Osborn et al. (2011) suggests that leaky well casings are most likely the reason for the elevated methane concentration, although upward migration of gas or gas-holding solutions is theoretically speaking also an option. The absence of brines seems to rule out rapid fluid displacement to the surface and the thick layer in between the shale layer and the aquifer makes upward migration unlikely

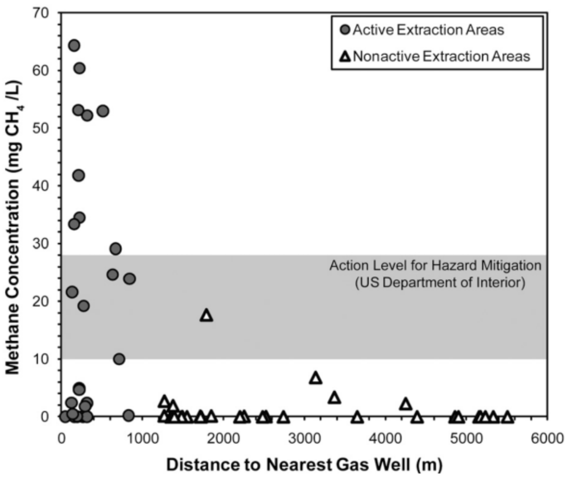


Figure 19 – Methane concentrations (milligrams of CH_4/L) as a function of distance to an active gas extraction area. (Osborn et al., 2011)

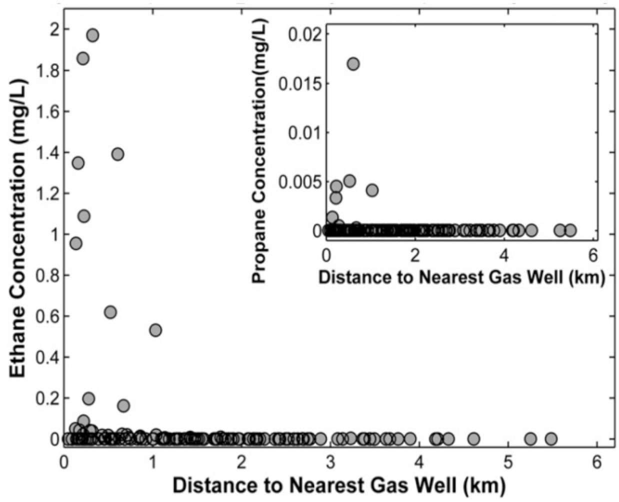


Figure 18 - Ethane and propane concentrations (milligrams/L) as a function of distance to natural gas wells. (Jackson et al., 2013)

The research of Osborn et al. (2011) was updated by Jackson et al. (2013), who came to the same conclusions and also showed the elevated concentrations of ethane and propane in wells located near natural gas wells (see Figure 18). They also examined correlation between methane concentrations and distance near discharge streams and geological deformations but distance to natural gas wells seemed to be the dominant factor.

Boyer et al. (2012) also examined private water wells and found no major influence of water being contaminated due to natural gas extraction or hydraulic fracturing. One of the 26 wells examined within a 800 meter radius of a Marcellus gas well pad where fracking had been performed showed elevated concentrations of all kinds of water quality parameters (including bromide, chloride, TDS-levels and more). Concentrations did not exceed any of the Safe Drinking Water Act norms. Fracking had been performed a few days before the sample was taken. After 10 months, another sample was

[20] Private water wells are a reason of concern in relation to contamination since they are often unregulated and not tested for water quality. The samples were taken from wells in Pennsylvania and New York where private water wells for household and agricultural purposes are quite common. Pennsylvania holds an estimated one million private wells (Osborn et al., 2011).

taken and all values had returned to their normal levels. According to the researchers, the elevated concentrations could have been a result of water well water mixing with brine which typically shows high concentrations of bromide and chloride (Boyer et al., 2012).

DiGulio et al. (2011) did a study on groundwater contamination in Pavillion, Wyoming after complaints by private well owners on the strange taste and odour of the water. The gas industry is active in this area in exploiting the Pavillion gas field and fracking occurs on as shallow a depth as 372 metres. Next to the 169 gas wells in the area there are 33 surface pits which are used for storage or disposal of flow back waters which produced brine. Several of the contaminants found were linked to hydraulic fracturing fluid and the overall conclusion of the study was that constituents associated with hydraulic fracturing fluid were released in aquifers used for water production. Closer investigations of wells showed several cases of compromised well integrity: upward migration (along the wellbore or via the formation) was appointed as a likely cause for the contamination.

Rozell & Reaven (2012) performed a risk analysis for water pollution due to natural gas extraction in the Marcellus shale. They based themselves on, amongst other sources, data of crashes involving the transport of hazardous chemicals, data on gas well failings, data on wastewater treatment volumes and data on onsite spills during drilling operations. The epistemic uncertainty in their dataset was quite large, which is why they used a best and worst case scenario. In general, the best case scenarios followed parameter estimates from the natural gas drilling industry and the worst case scenario used estimates from environmental organizations. Contamination was seen as anything that could potentially exceed limits as imposed by the Safe Drinking Water Act and Clean Water Act and focussed solely on the drilling and the hydraulic fracturing fluid part. Uncertainty (and possible impact) was largest in potential contamination due to wastewater disposal, followed by the risk of well casing failing and the corresponding portion of fluid leaking. Although their results should be interpreted with caution, their best case scenario shows a very likely chance of a single well releasing 200 m3 of contaminated fluids into the environment (see Figure 20). The figure below depicts a probability box of the best case scenario: it is evident from the probability (y-axis) that the contaminated volume released is lower than the depicted value on the x-axis. In other words, there is a 100% chance the contaminated volume is lower than 600 m^3 and a 65% chance the contaminated volume is lower than 200 m^3.

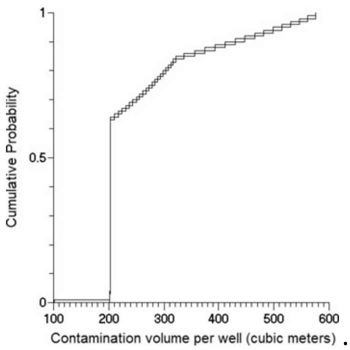


Figure 20 – Probability box: best case scenario for contaminated volumes of water released to surface waters due to waste water disposal. (Rozell & Reaven, 2012)

More information can be found in Table 6, which shows that the potential impact from waste water disposal is definitely the largest, partly due to the fact that treatment at POTW's is not suitable for most water and which therefore leads to large contaminations after the treated volumes are discharged. The 50th percentile numbers indicate there is a fifty percent chance the contaminated volume is lower than the volume displayed. The maximum epistemic uncertainty between the best case and worst case scenario represents the range between the minimum and maximum values achievable (minimum usually zero).

Table 6 - Comparison of Water Contamination Pathway Risks from Hydraulic Fracturing in a Typical Marcellus Shale Gas Well. (Rozell & Reaven, 2012)

Pathway	Best-Case 50th Percentile Contamination Volume (m^3)	Worst-Case 50th Percentile Contamination Volume (m^3)	Maximum Epistemic Uncertainty Between Best and Worst Case (m^3)
Transportation	< 0.01	0.3	0.6
Well casing failure	< 0.01	9	60
Fracture migration	< 0.01	225	270
Dilling site spills	< 0.01	3	15,000
Wastewater disposal	202	13,500	26,900

It should be noted that this study focusses on the Marcellus shale, where underground injection of waste water, which is the most common way for disposal in the oil- and gas industry, is not available. Average numbers for the whole country are therefore probably a lot lower since this method is more secure.

4.1.7 Well casing failure

As mentioned before, the fracking occurs at much greater depths than the aquifers used to provide drinking water, and the two are separated by hundreds of meters of impermeable rock. However, the borehole connects them in a straight line, providing a potential pathway for fluid migration in case the structural integrity of the casing is compromised. In addition, after a well is abandoned the well needs to be plugged to prevent additional fluids or gas present in the formation from escaping. Oftentimes, cemented plugs are used and concrete deterioration is a potential long-term source of contamination. Furthermore, the inherent nature of shale gas drilling makes it somewhat more susceptible to the failing of well casings, due to the need for deviated wells and disturbance of young cement by adjacent nearby drillings in the case of pad drilling (Ingraffae, 2012).

A state-wide examination across Pennsylvania showed that compromised well integrity in newly drilled wells is fairly common: 6-7% of the newly drilled wells between 2010-2012 were dealing with compromised well integrity as reported to the Department of Environmental Protection in Pennsylvania (Ingraffae, 2012). This number could be higher due to operators not reporting incidents or unnoticed failures in casing. Also, the leakages found in this study were all noticeable at the wellbore by elevated methane concentrations: the potential for leaking casings not being picked up in the analysis is therefore larger.

At the end of the lifetime of a well, the borehole is plugged with a cemented plug. Filling up the complete wellbore with cement would be too costly, so often a plug is placed on the bottom of the well and additionally on the top and across certain geological zones if deemed necessary. Although the practice of cemented plugs is common in the oil and gas industry and seems to provide a good seal for the near future, there are several mechanisms in place which could result in long-term complications. Corrosion and cement leaching (which is the process of dissolution of hydrates) will alter the composition of the cement and reduce the strength of casings and well plugs in the long-term (Guen et al., 2009). Little research has been done on this topic as most plugged wells are not old enough to provide a dataset on long-term risks for leaking. Guen et al. (2009) did a risk analysis for CO2-storage wells and the model showed that cemented casings across all different geological zones were experiencing breakthroughs after a 1000 year period, with rates varying per zone. Due to the preliminary nature of the research of Guen et al. (2009) and a lack of data, hard conclusions cannot be drawn, but common sense dictates that wellbore integrity is eventually compromised over time. Whether deterioration is an issue over hundreds or thousands of years is probably dependent on the singular properties of individual wells.

4.1.8 Seismic activity

Seismic activity has traditionally been associated with the oil and gas industry, and the debate on shale gas is no different in the sense that there are worries about increased seismic activity due to wide-spread fracking. Recent earthquakes in the UK of 1.5 and 2.3 $M_{L,}$ and the following suspension of activities by the operator, have further fuelled the debate on seismic activity and fracking[21]. Although the fracking process itself induces micro-seismic activity by putting high pressure on a formation, these tremors are generally too small to notice on the surface (RS & RAE, 2012). However, when pre-stressed faults are located near the hydraulic fracturing zone, fracking can induce larger earthquakes (Peters, 2013; RS & RAE, 2012)[22].

The induced seismicity is dependent on the pressure build up in the hydraulic fracturing zone, which is in turn dependent on (RS & RAE, 2012):

- Volume of injected fluid and the volume of the flow back as larger volumes in the formation create higher pressures;
- The injection rate and the flowback rate as more rapid injection generates higher pressures and more rapid flowback rates reduce pressure

Normal seismic events (i.e. no pre-stressed faults involved) due to hydraulic fracking are not expected to surpass 3 M_L (Green et al, 2012). This is based on data on seismic activity due to coal mining in the UK. The energy released during hydraulic fracturing is in general lower than energy released in formation collapse due to coal mining. This is because of the fact that shale layers have a low permeability and therefore subsidence is lower, i.e. the empty void present in the formation collapsing is smaller compared to coal mining (RS & RAE, 2012). In addition, hydraulic fracturing usually takes place at greater depths compared to underground coal mining, resulting in a reduced transmission to the surface (Green et al, 2012). Structural damage on the surface with these magnitudes is unlikely (Green et al, 2012)[23]. Figure 21 shows various seismic events linked to hydraulic fracturing. The Bowland shale depicts the recent earthquakes in the UK: both of the seismic events were correlated to pre-stressed faults which were not identified beforehand (Green et al., 2012). Enhanced geothermal energy wells also require fracking and a closed system of constant circulation: the areas were the events occurred (Basel and Soultz deep) are known for the natural tensions present in the underground which probably led to the high magnitudes (Peters, 2013). Also, the constant circulation of the fluid leads to pressure over a longer time, where in hydraulic fracturing, the pressure is exerted on a much shorter timeframe. Recent earthquakes in the Netherlands due to conventional gas extraction reached a magnitude of 3.6 on the Scale of Richter. Hydraulic fracturing in Canada has led to considerable seismic activity: again this was linked to fluid injection near pre-existing faults (BC Oil and Gas Commission, 2012). The majority of the seismic activity due to hydraulic fracturing is in the low range, indicating that if faults are well mapped and taken into account damage due to seismic activity is unlikely.

[21] M_L= Local Magnitude, also known as the Richter Scale.
[22] When fluid enters the fault, the friction holding the formation together is reduced due to chemical alteration, and pressure builds up which stresses the foundation which may reduce the overall solidity of the formation. This in turn can lead to induced earthquakes.
[23] According to Green et al. (2012) seismic activity induced by underground coal mining has not led to structural damage on the surface.

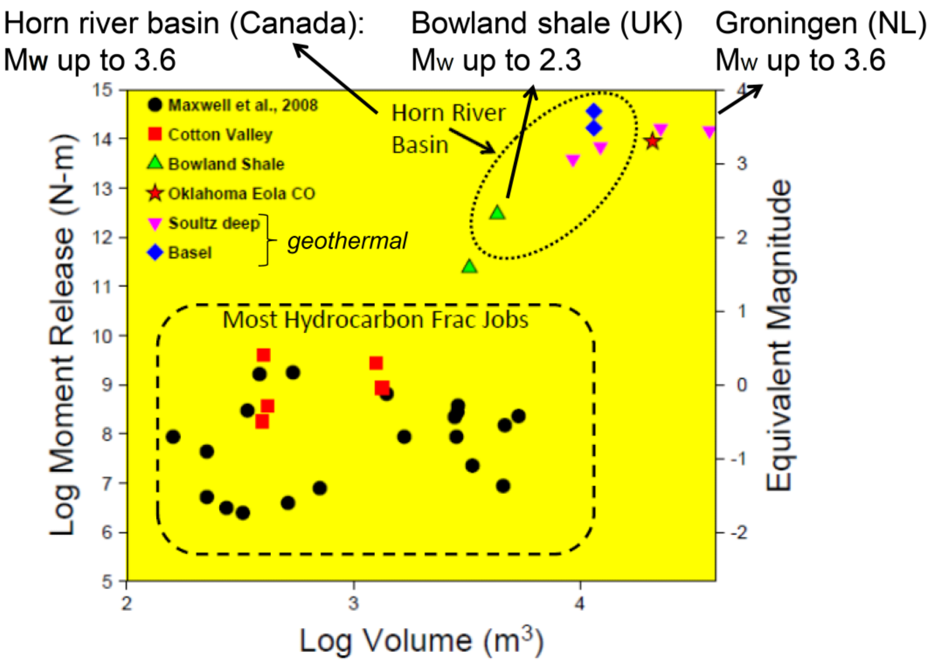


Figure 21 - Seismic Activity due to hydraulic fracturing. (Rutledge, 2012 In: Peters, 2013)

Bigger seismic risks are involved with the injection of waste water into disposal wells. The nature of the process creates bigger risks compared to hydraulic fracturing as there is no flowback and much larger volumes and injection rates are involved. This causes large amounts of pressure building up over time, inducing more vigorous seismic activity. RS & RAE (2012) concluded after a literature review that the magnitude of earthquakes due to wastewater disposal typically does not exceed 5 M_L. Furthermore, it should be noted that 140,000 disposal wells have been operated for decades in the U.S. and no serious damages or injuries due to induced seismicity have occurred during that time (Zoback, 2012).

4.2 Emissions

Proponents often promote shale gas as a bridge fuel to the future, replacing coal and complementing renewables. Opponents point out that fugitive methane emissions could make the lifecycle carbon footprint of shale gas worse than the industry claims and perhaps even worse than coal. The following section will therefore focus on the various estimates of life-cycle emissions of shale gas available in the literature, along with a comparison to conventional natural gas and other energy carriers.

4.2.1 Lifecycle emissions

Weber & Clavin (2012) have gathered several peer-reviewed LCA's and compared them with each other. Several estimates with respect to upstream emissions have been made for the European and the Dutch situation. Most studies also gave an estimate for the carbon footprint of conventional gas, which allows for comparison between the two types[24]. Upstream emissions were defined as being upstream from the power plant gate and were displayed as g CO_2-eq/MJ_{LHV}. Figure 22 gives an overview of all the estimates. Note that the estimate of Howarth et al. (2011) is presented for two Global Warming Potential (GWP) time horizons. The argument for the use of a shorter time horizon is

[24] Hultman et al. (2011) did not provide an estimate for conventional gas.

discussed in section 4.2.3. Unless otherwise specified, the estimates will adhere to a 100 year time horizon of GWP. For comparability, further references to Howarth et al. (2011) in this section will refer to the 100-year GWP time horizon estimate. An overview of emission occurrence in the various lifecycle stages is shown in appendix Appendix B. Emission sources

The majority of the studies focussing on the United States estimated a range of 13-15 g CO_2-eq/MJ_{LHV} for the upstream emissions., Howarth et al. (2011) constituted the upper limit with 26,6 g CO_2-eq/MJ_{LHV} and Stephenson et al. (2011) formed the lower limit with 8.3 g CO2-eq/MJ_{LHV}. Upstream emission factors for Europe and the Netherlands seem to be much smaller, between 5.5-6.1 gCO_2-eq/$MJ_{LHV.}$ Possible explanations lie in stricter environmental regulations, better gas infrastructure and shorter transport distances.

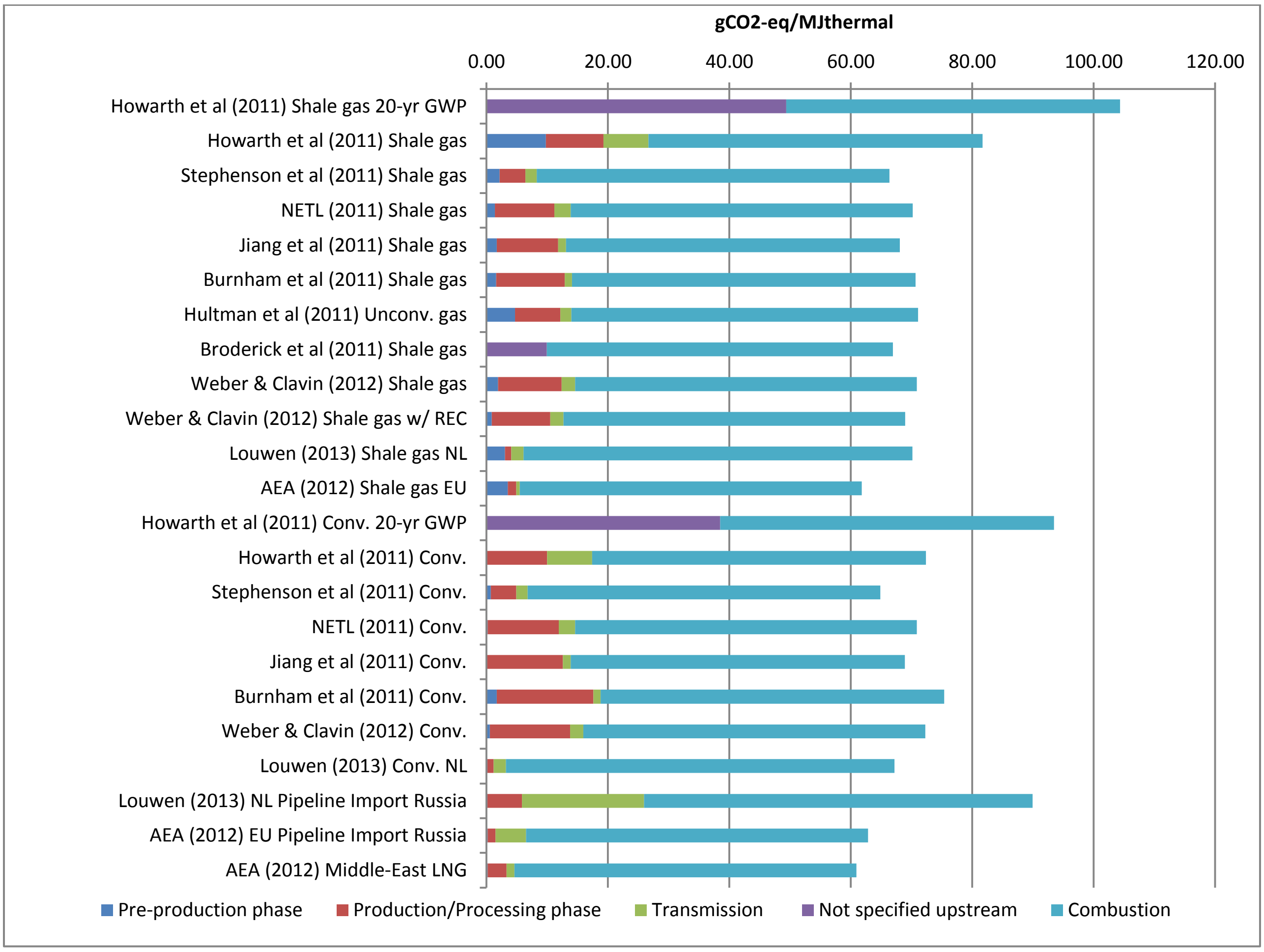


Figure 22 - Upstream emissions for shale gas, conventional gas and imported gas. Inclusion of emission sources can differ between estimates. If a range of values were found for an emission source was the best estimate, average or median value is displayed. Emission factors from Howarth et al (2011), Stephenson et al (2011), NETL (2011), Jiang et al. (2011) and Hultman et al. (2011) are extracted from the overview of Weber & Clavin (2012). AEA (2012) import values refer to conditions within the United Kingdom. If the emissions due to combustion were not given, an average from Weber & Clavin (2012) is displayed (56.3 gCO2-eq/MJ). If lifecycle emissions had to be converted to upstream emission estimates and the assumed efficiency of the power plant was unknown, an efficiency of 52.5% was assumed (AEA, 2012). Studies refer to the United States unless otherwise specified.

The high estimate of Howart et al. (2011b) originates from the assumption made on high emissions during well completion and high fugitive emissions during transmission[25]. The Stephenson et al. (2011) low estimate can be explained due to low energy use assumptions and emissions in the field as well as during the refining process. The degree of flaring seems to be a factor to which the overall emission profile is quite sensitive as well (Weber & Clavin, 2012)[26]. Howarth et al. (2011) assumes a flaring rate of zero, which leads to large emissions in the preproduction phase. However, emissions during well completions can be mitigated by flaring or Reduced Emissions Completions (REC). REC consists of capturing the gas that otherwise would be vented and processing it for sale. Gas emissions of this source often occur after the fracking, after which the well must be cleaned and the proppant separated from the flow back water. During this process, methane is dissolved in the flow back water, which, in the case of open pit storage, can escape into the atmosphere. Another issue is

[25] Fugitive emissions during transmissions Howarth et al. (2011): 6,8 g CO_2eq/MJ ; Range of other studies for the USA: 0.9-2.3 g CO_2eq/MJ. Well completion emissions Howarth et al. (2011): 8.6 g CO_2eq/MJ; Range of other studies: 0.8-4.7 g CO_2eq/MJ.

[26] The global warming potential of CH_4 is 25 times higher than CO_2.

that the wellhead is exposed during well cleaning, which also causes methane emission to the atmosphere. By using a closed system for retrieving flow back water and well cleaning, the amount of time the wellhead is exposed to the atmosphere decreases along with the fugitive methane emissions. This is especially useful for shale gas since a well often needs to be fracked more than once. EPA has proposed regulations regarding REC, making it mandatory starting from the beginning of 2015. In some states it is already mandatory. Some operators already adopt these practices voluntarily (EPA, 2012b). Another factor influencing the high estimate of Howarth et al. is the high level of emissions during transmission. Pipeline transport always leads to some fugitive emissions of methane due to leaks in the transmission system. Howarth et al. took all losses in the transmission system as emitted into the atmosphere. Additionally, he took data for transmissions losses from the Russian distribution system while it is likely the U.S. system leaks less than the Russian system. Fugitive emissions in the distribution system were taken from the difference in volume measured at the wellhead and volume sold. Part of the losses can be explained by theft, on-site fuel use and variations in measurements due to ambient temperature variations and liquid unloading, factors not separately accounted for in this number (Burnham et al., 2011). The high emissions due to gas transmission in the Russian pipeline system can also be seen in the estimate of Louwen (2013). It is not clear why the AEA (2012) estimate for imports from Russia is considerably lower. Louwen (2013) mentions the large uncertainty with respect to the emission factor for Russian gas transport in the database used.

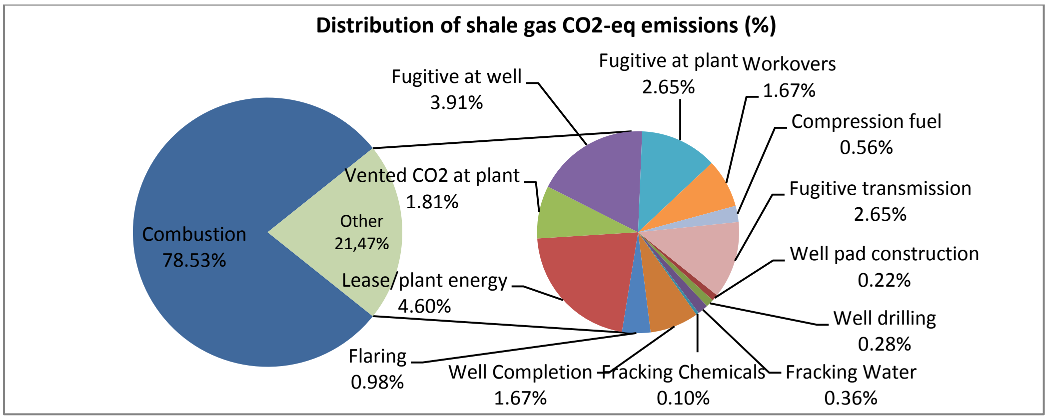


Figure 23 - Distribution of lifecycle shale gas CO2-eq emissions by source using an averaged emission factor for combustion over the six studies (56.3 g CO2/MJ). (Data from: Weber & Clavin, 2012)

Overall the estimates show a comparable footprint for conventional gas and shale gas. Conventional gas wells often produce more water and liquid hydrocarbons as they mature (see Figure 5) (Weber & Clavin, 2012). These liquids can build up in the wellbore, impeding gas flow: as a result the wellbore needs to be cleaned more often, leading to fugitive emissions into the atmosphere (a so called well-work over). Shale gas wells are typically dry and are therefore often exposed to the atmosphere only after well completion in the case of re-fracturing (which occurs less often than liquid unloading).

Most emissions occur during the combustion phase. The amount of emissions is dependent on the efficiency of the natural gas fleet. A well-to-wire analysis done by Weber & Clavin (using their best estimate resulting from the Monte Carlo simulation) is shown in Figure 24. Included is the average natural gas powerplant fleet over time, a single cycle steam plant and a NGCC.

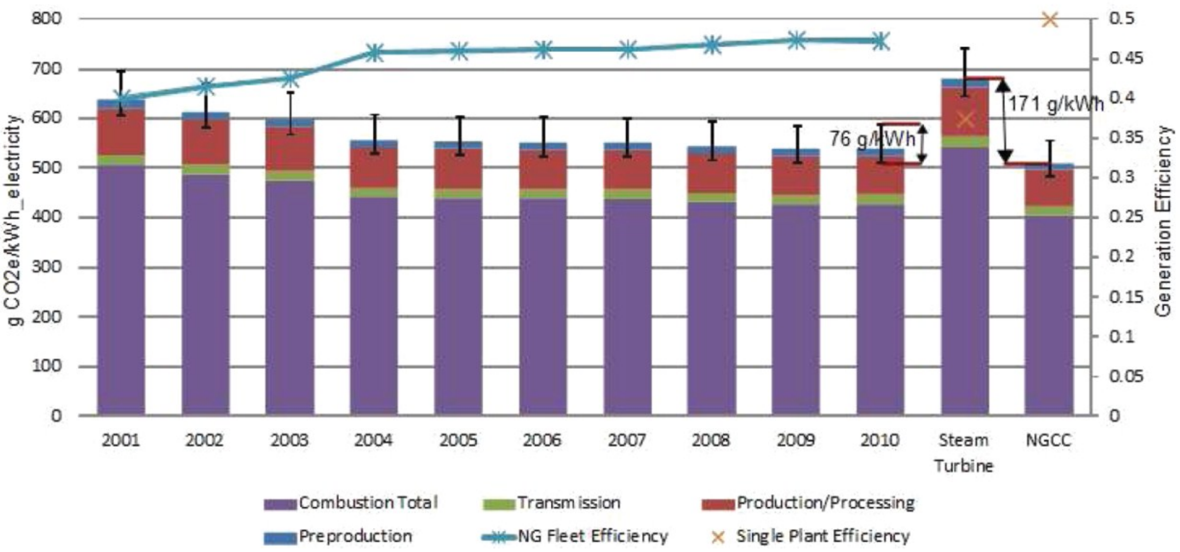


Figure 24 - Well-to-wire emissions of shale gas for average U.S. NG-fleet efficiencies, a single cycle steam turbine plant and a NGCC. (Weber & Clavin, 2012)

4.2.2 Comparison to other energy carriers

The IPCC has made an inventory of emission intensities for the combustion of various fuels after an extensive literature review (Moomaw et al., 2011). A comparison between the IPCC results and the Weber & Clavin (2012) best estimate can be seen in Figure 25. It has to be noted that the Weber & Clavin estimate is a U.S.-based value, whereas the IPCC values represent a literature review not restricted to the U.S. The range of values found in the multitude of studies used is represented by percentiles. Overall, the U.S. value for shale gas is slightly higher than the 50th percentile value mentioned for natural gas as a whole in the IPCC. Taking all factors into account, it seems unlikely shale gas has a bigger CO_2-eq-footprint compared to coal or oil in the case of electricity generation. It seems the footprint of conventional natural gas and shale gas are comparable, although specific situations could lead to a higher footprint of shale gas. The role of methane leakage seems to play a crucial role here, and applied technologies can cause a big difference. A key uncertainty lies in the fact that most of the upstream emissions occur only once in the lifetime of a well. In order to make an estimate of GHG emitted per unit of energy, one has to estimate the Energy Ultimately Recovered (EUR) from the well. EUR data is highly location specific and since very few wells have been depleted yet, data is very limited on the EUR. In addition, there is some controversy over applied calculation methods for EUR values, which leads to a wide range of values mentioned in literature. See section Productivityfor a more in-depth overview of these matters.

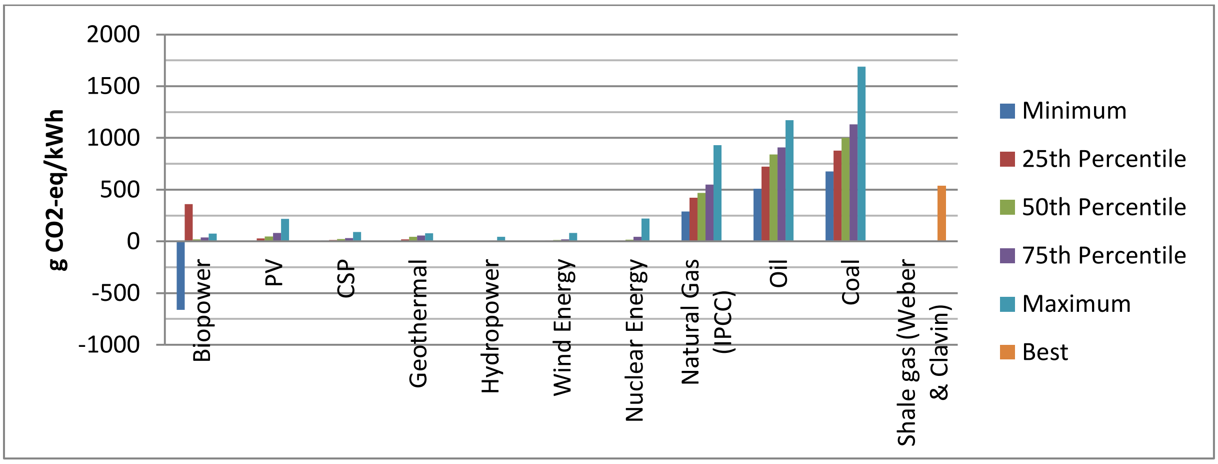
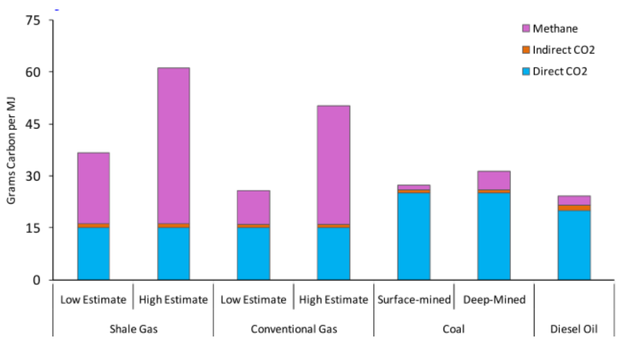


Figure 25 - Life cycle emissions for electricity generation by source. For the shale gas emission intensity the best estimate of Weber & Clavin (2012) was taken. (Data from: Moomaw et al., 2011; Weber & Clavin, 2012)

4.2.3 Controversy over methane leakage

The argument that life cycle emissions of shale gas could exceed those of coal stems mainly from an article written by Howarth et al. (2011a, b), which was published in Climatic Change and featured in Nature. The authors examined the lifecycle carbon footprint of shale gas for heating and compared it to other fossil fuels such as conventional gas, coal and diesel oil. The fact that they calculated it for heating differs from most studies, which focus on the lifecycle carbon footprint of shale gas for electricity generation and therefore gain an additional advantage over coal due to the high efficiency of natural gas fired power plants compared to coal-fired power plants. Additionally, they presented their results using two different time horizons concerning the GWP of methane, a 20-year and a 100-year time horizon. Although the IPCC recommends using a 100-year time horizon, the authors argued that the need to reduce global warming in the coming decades justifies the use of 20-year GWP. Furthermore, they used a somewhat higher GWP than prescribed by the IPCC (105 and 33 compared to 72 and 25): this was done to account for recent insights into methane and aerosol interactions not included in the IPCC 4th Assessment from 2007. Along with the high leakage rates described earlier, this leads to a considerably higher carbon footprint for shale gas per MJ of heat energy delivered, however, with this method of calculation conventional gas could also perform worse than coal.



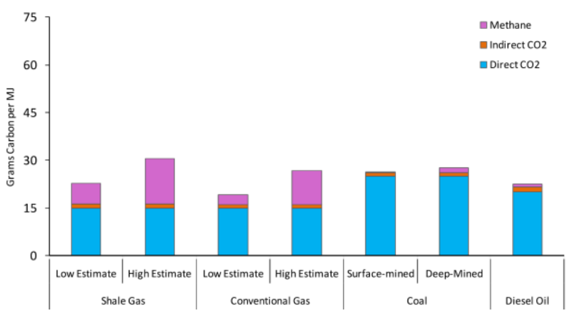


Figure 26 - Lifecycle emissions of shale gas compared to other fuels. Left: 20-year time horizon for the GWP of methane. Right: 100-year time horizon for the GWP of methane (Howarth et al., 2011).

4.3 Productivity

4.3.1 Productivity of wells

As mentioned in the previous chapter, the lifecycle emissions of shale gas are dependent on the Expected Ultimate Recovery (EUR) of a well due to one-time emissions in well completions and drilling. To be able to assign those emissions to an energy content, the EUR is needed. The same goes for an economic assessment of a well (assigning costs over expected energy content), and establishing reserve and resource estimates. The EUR of a well could be considered the most crucial factor for evaluating the potential of shale gas, as this is the variable which will determine how much energy can be retrieved (and sold) for a certain investment of money and energy. However it is also one of the most uncertain factors in shale gas production. There is a lack of data regarding long-term prospects, and there are rumours of manipulation by the industry with respect to the decline curve data in order to sketch a more positive image for investors and shareholders (Urbina, 2011). Another factor to be taken into account is that estimates of the average EUR of a formation are highly location specific. Productivity of a well within a formation can vary by a factor 10, and even wells located next to each other can vary by a factor 3 (EIA, 2012d). Since resources are exploited in order of favourability, the current shale gas wells are located within the so-called sweet spots. Estimates of the EUR of a formation based on the productivity of existing wells could therefore over-estimate the total potential as future wells would probably perform worse (EIA, 2012d). On the other hand, the technique is relatively new and technological advances could boost future production rates. Considering the vast size of shale formations, the current sample size on productivity is still relatively small. For this reason using productivity data from existing wells in the formation still does not give a clear indication of future productivity[27]. In order to understand the controversy concerning the calculation of the EUR, it is necessary to understand the differences in production mechanisms between conventional gas and shale gas. In this section these differences will be explained, followed by the EIA estimates for EUR since they seem to be most authoritive source in the matter.

4.3.1.1 Reservoir drives

The production rate follows from a pressure difference between the wellbore hole and the reservoir: a lower pressure at the wellbore hole will lead to a flow of hydrocarbons from the reservoir to the surface. Naturally it would be expected that as soon as production starts, the pressure decrease would lead to a smaller production rate. However, there are some reservoir mechanisms in place which can maintain the production rate stable for a prolonged period. Several reservoir drives need to be mentioned (Hartmann & Beaumont, 1999):

- Water drive: if an aquifer is present beneath the gas/oil layer, the water will be slightly compressed due to the pressure present in the reservoir. As the pressure decreases due to hydrocarbon extraction, the water will expand. This expansion can maintain the pressure on the hydrocarbons and therefore on the production rate. Also, the influx of water into the aquifer can maintain the pressure on the hydrocarbons. A distinction can be made between strong water drive and partial water drive, which describes a difference in size and quality of the water drive.
- Gas expansion drive: as the pressure decreases in a reservoir the free gas will expand and therefore maintain pressure near the wellbore hole.
- Dissolved gas drive: If oil is present in the reservoir it may contain dissolved gas. The compressibility of the oil is dependent on the amount of dissolved gas. Pressure reductions in the reservoir lead to expansion of the oil and therefore the production rate is maintained. When the pressure on the oil becomes low enough gas bubbles will form which will form a layer of free gas which also forces the hydrocarbons out as it expands.

[27] For almost every shale formation 98-100% of the area remains untested at the moment. (EIA, 2012e)

- Rock or compaction drive: as the reservoir pressure declines, the pressure on the rocks increases due to the fact that the reservoir fluid no longer carries the pressure on the solids. This can lead to a collapse of the pores present in the formation, thereby forcing the hydrocarbons to the wellbore hole.
- Gravity drainage: gravity may cause oil in a reservoir to move downward and gas in a reservoir to move upward. The weight of the hydrocarbons above the wellbore hole will exert a pressure on the lower situated hydrocarbons, which can be used as a drive mechanism.

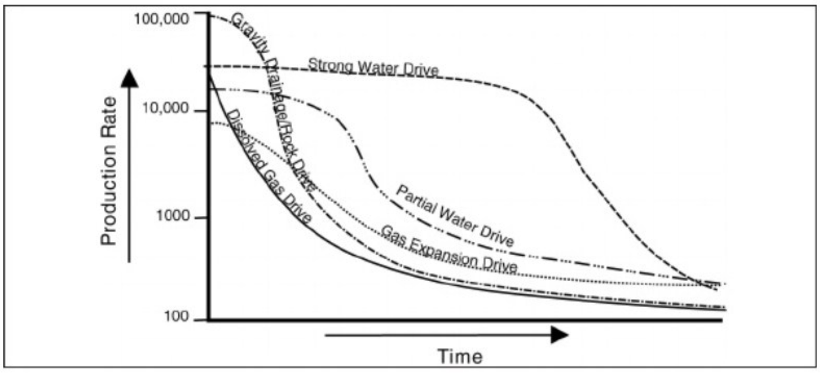


Figure 27 - Typical production decline curves for several drive mechanisms in reservoirs with the same pore volume (Hartmann & Beaumont, 1999).

Conventional gas can be found in the form of non-associated gas (no oil present), associated gas (dissolved within the oil) or capped gas (distinct layer of gas above a layer of oil) (see Figure 5). Drive mechanisms for conventional gas will therefore mainly exist in the form of water drive (strong and partial) and gas expansion drive. As seen in Figure 27 - Typical production decline curves for several drive mechanisms in reservoirs with the same pore volume (Hartmann & Beaumont, 1999).a water drive (strong ones in particular) can maintain the production rate stable for a long time. A conventional, non-fractured reservoir is continuous with a relative homogenous permeability throughout the play leading to a steady loss of pressure (governed by the several reservoir drive mechanisms). However, hydraulic fractured reservoirs have a heterogeneous permeability in the reservoir: the fractured permeable part which releases gas rather fast in the short-term (transient linear flow) and the surrounding, non-fractured, matrix surrounding the fracture from which gas can seep more slowly into the fractures on the long term (boundary-dominated flow) (Xu et al., 2013). The low permeability of the matrix further complicates the picture by inhibiting a strong water drive as the pressure on a deep aquifer will not be directly translated to the gas.

4.3.2 Initial production rates

Production profiles of shale gas wells show a general trend of high initial production rates which decline rapidly in the first years after which the decline rate moderates. Advancements in reservoir evaluation, well stimulation and well completion have led to improvements in initial production rates over the years (Baihley et al., 2011). However, the distribution per well still varies a lot and improvements are not seen in every field, despite the advances. In 2009 the average initial production rates (30-day average) for the several major plays in the US varied between 2000-8000 Mcf/day (or 54 453 – 224 350 m^3/day) (Jacoby et al., 2011)[28]. Decline rates in the first year are as steep as 60-80%, and after 4-5 years they seem to be reduced to 10% a year (Jacoby et al., 2011). In

[28] 1 mcf≈28,3 m^3. Barnett, 1923 mcf/day; Fayetteville, 2183 mcf/day; Hanyesville, 7973 mcf/day; Marcellus, 3500 mcf/day; Woodford, 2676 mcf/day.

comparison, an average conventional gas well in the Groningen field produces 3 million m^3 a day (note that this is an average production rate so average initial production rates should be even higher) (Herber, 2013).

4.3.3 Decline curve analysis

The EUR of shale gas wells is mostly estimated by decline curve analysis (Lee & Siddly, 2010. In: Denney, 2010). Decline curve analysis tries to predict the future production rates of a gas well by curve fitting or applying a decline curve of an older well to a new play. The EUR is reached when the production rate of the well can no longer justify the costs of maintaining the well (Lee & Siddly, 2010. In: Denney, 2010).

Figure 28 shows the process of the decline curve analysis. After twelve months of production, a curve fitting method predicts an EUR of 33 million m^3 (the area beneath the curve). However, the 24 month production data shows a more rapid decline than expected, resulting in a new EUR estimation of 18 million m^3 (Herber, 2013). A small difference in daily production rate can result in a large difference in estimated EUR.

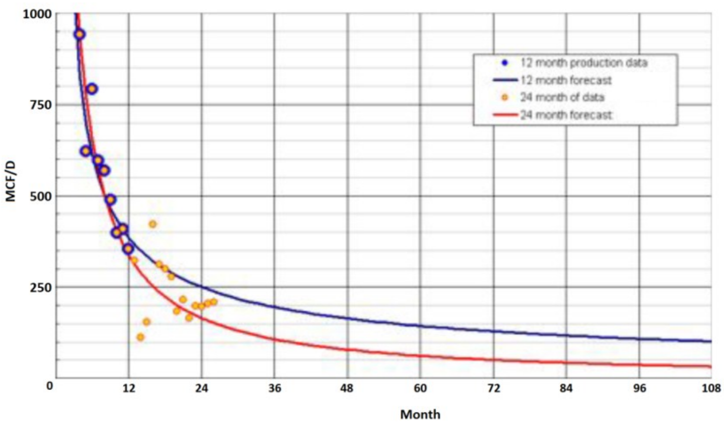


Figure 28 - Decline curve for a shale gas well. (Herber, 2013)

Traditional curve fitting is done using Arps formula (see Eq. 1), which was developed for boundary-dominated flow conventional reservoirs (Xu et al., 2013). The formula consists of several components: initial production rate, initial decline rate and a component which determines the curvature of the decline rate.

$$q(t) = \frac{q_i}{(1+bD_it)^{1/b}} \quad \text{(Eq. 1)}$$

Where:
$q(t) = Production\ rate\ at\ time\ t$
$q_i = Initial\ production\ rate$
$b = curve\ fitting\ exponent$
$D_i = Initial\ decline\ rate\ per\ unit\ of\ time$
$t = time\ t$

The component determining the curvature is called b and it determines whether the function is hyperbolic or exponential. If 0<b<1, then b is exponential and experiences a cut-off point; if 1<b then the graph is hyperbolical and production rates continue to infinity (in which case an artificial cut-off point has to be introduced). There is some controversy in the industry regarding using values for b exceeding 1 (Baihley et al., 2011). Another issue is that it is beyond the limit for which the formula is specified and it leads to unreasonable physical properties (Lee & Sidle, 2010 In: Denney, 2010).

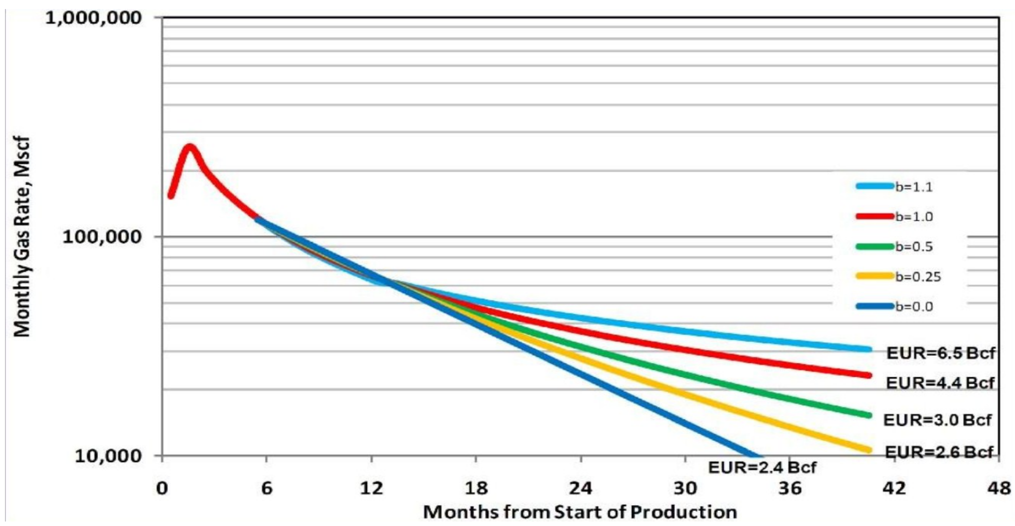


Figure 29 - Haynesville shale gas well production rate decline and EUR based on different values for b. (Berman, 2012)

The value of b has a substantial influence on the final EUR (see Figure 29) and analysts differ in opinion on which methods are acceptable or not. Operators tend to have no problem with values of b exceeding 1. A survey of shale gas wells showed that some plays based on Arps formula have a b-values exceeding 1 (e.g. Barnett shale 1.59) (Baihley et al., 2011). Opponents, however, argue that this method does not take into account the switch from transient linear flow to boundary-dominated flow, and the actual long-term decline rates cannot be extrapolated from the initial period (Berman & Pittinger, 2011). They argue that it could very well be that the rate at which the decline rate becomes smaller over time (lengthening production) diminishes (i.e. the decline rate stabilizes after a certain time period) (Berman & Pittinger, 2011; Urbina, 2011). Little peer-reviewed literature exists on the matter and critiques come from insider leaks or analysts and experts publishing in the media. The research that exists admits that it is an opaque matter but does not shed further light on the matter (Baihley et al., 2011). It is clear, however, that the Arps formula is developed for boundary-dominated gas flows with b-values between 0 and 1: these criteria are not necessarily met in shale gas reservoirs. Although it is probably the most accurate method at the moment for EUR prediction in shale gas wells, caution should be applied to predictions of the EUR based on high values of b.

The EIA (2012e) estimates the EUR for shale gas wells based on a 30-year time period with decline curve analysis (Table 7). The major plays vary between 1,30-2,67 bcf/well, and some of the smaller plays have much lower values. The ranges show the wide distribution of productivity values within a play. Due to the high decline rates, a major part of the EUR is recovered within the first few years of production. In the first four years of production, between the 65%-95% of the EUR is produced for the major plays (EIA, 2012e). Therefore, significant additional drilling needs to take place in order to maintain current production levels.

Table 7 - Average EUR per well and range found within plays (EIA, 2012e)

Basin/Play	Average EUR per well bcf (million m3)	Range bcf
Appalachian		
Marcellus	1,56 (43,9)	0.02—7.80
Utica	1,13 (31,8)	0.10—2.75
Arkoma		
Woodford	1,97 (55,4)	0.40—4.22
Fayetteville	1,30 (36,6)	0.19—3.22
Chattanooga	0,99 (27,8)	0.14—1.94
Caney	0,34 (9,6)	0.05—0.66
Texas-Louisiana-Mississippi Salt		
Haynesville/Boosier	2,67 (75,1)	0.08—5.76
Western Gulf		
Eagle Ford	2,36 (66,4)	0.41—4.93
Pearsall	1,22 (34,3)	0.12—2.91
Anadarko		
Woodford	2,89 (81,3)	0.68—5.37

It is unclear what happens in the long-term since operators mostly use a hyperbolic curve fitting procedure. In case of a hyperbolic decline curve, the decrease in production rate keeps becoming smaller over time and the decline curve is asymptotic. In other words, the decline rate keeps becoming smaller over time, following the trend observed during the initial production stages, and production rates keep becoming smaller ad infinitum.

However, some analysts think that after the high initial production rates the production curve will become exponential, indicating a steady decrease in production rate over time. In other words, after the initial production decline the trend changes, leading to a stabilization of the decline rate over time, leading to a cut-off point. The argument stems from a geological difference in the reservoir when fractured. A conventional, non-fractured reservoir is continuous with a relative homogenous permeability throughout the play, leading to a steady loss of pressure (governed by the reservoir drive mechanisms). Hydraulic fractured reservoirs, however, lead to a heterogeneous permeability in the reservoir: the fractured permeable part which releases gas rather fast in the short-term (transient linear flow) and the surrounding, non-fractured, matrix surrounding the fracture from which gas can seep more slowly into the fractures on a long term time scale (boundary-dominated flow) (Xu et al., 2013). This leads to a different mechanism of decline and for this reason they argue that changes in decline rates in the short term are not representative long term and that traditional curve fitting using a hyperbolic model is not correct.

4.3.4 Model

In order to study the effects of several of the parameters on the net present value of a shale gas well, a simple excel model was constructed. The inputs were specified as much as possible on wells located in the Barnett shale to make them comparable. Investment costs, operating costs, land lease cost, royalties paid to the land owner and production cost were taken into account. In order to be able to study the effects of a varying EUR, a static production curve was implemented which consisted of a 70% decline in year 1, a 30% decline in year 2, a 15% decline rate in year 3-4 and a constant decline rate of 10% after that. The lifetime of the well was set at 23 years. The initial inputs are shown in Table 8 and discounted cash flows over time are shown in Figure 30. A sensitivity analysis is shown in Figure 31. The net present value of the well under current gasprices is $ –222 859, showing it is not profitable to exploit. A gasprice of 3,89 $/mcf would be necessary for the well to break even. When looking at the spider diagram it can be seen that the gas price has the most influence on the break-even cost after which the EUR is the biggest factor. Varying conditions in the shale formations would therefore have a big influence in the expected profitability of a well. Also, slight variations in the investment cost could have a large influence on the EUR, showing the importance of achieving cost reductions in drilling and completion costs. This model excludes the co-production of natural gas liquids which can be sold at a higher price and thereby improve the overall economics of a shale gas well.

Table 8 – Input parameters for a hypothetical Barnett shale gas well. (Baihley et al., 2011; Jacoby et al., 2011; EIA, 2013; Lechtenbömer, 2011)

Inputs		Note	Source
Initial Production (Mcf/d)	1923	Average 30-day initial production rates in the Barnett shale	Jacoby et al (2011)
Gas price ($/mcf)	3.72	Henry Hub Gas price Sept 2013	EIA (2013)
Investment cost ($)	3500000	Mid estimate completion cost Barnett Shale	Jacoby et al (2011)
O&M cost ($/mcf)	0.75	Typical operating cost Barnett shale gas well	Jacoby et al (2011)
Royalties (%)	22%	Assumed royalty rate for the Barnett shale	Baihley et al. (2011)
Lease cost ($/acre)	5000		Jacoby et al (2011)
Well spacing (acres/well)	54.35	Local well spacing in the case of infill drilling in the Barnett shale	Lechtenbömer (2011)
Decline rate year 1 (%/yr)	70%		Baihley et al. (2011)
Discount rate (%)	10%		
EUR (BCF)	2.8	Assumed EUR for newly drilled horizontal wells in the Barnett shale.	Jacoby et al. (2011)
Production Taxes (%)	3%		

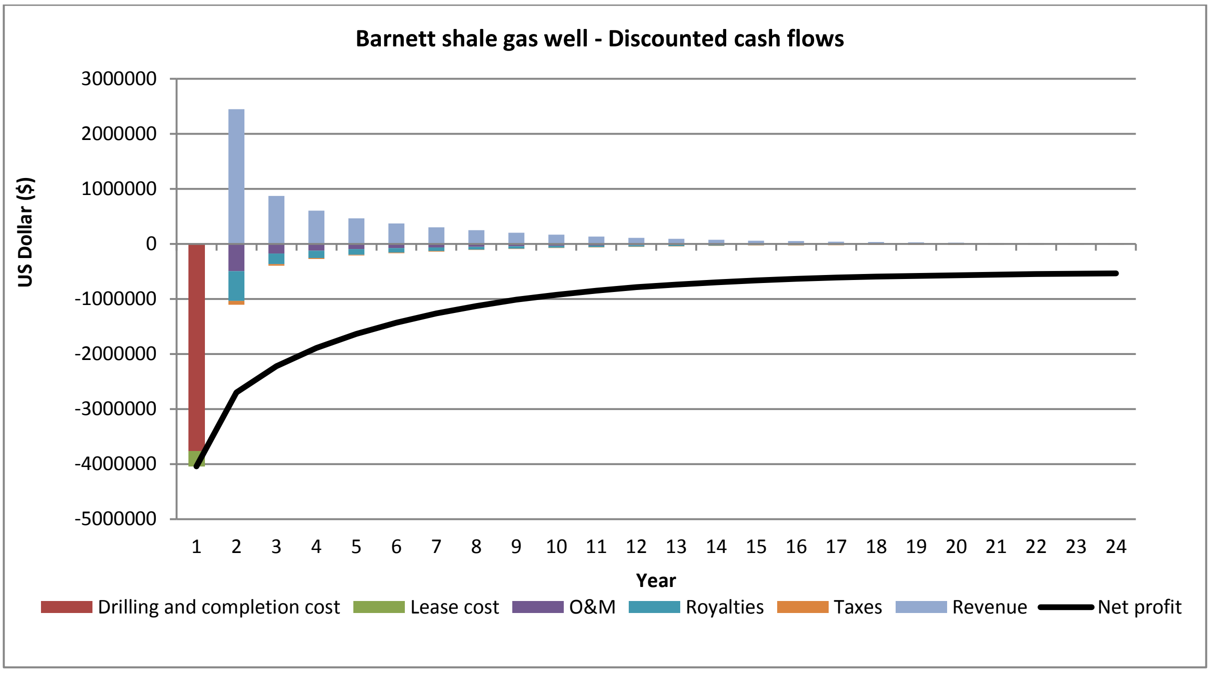


Figure 30 - Discounted cashflows and net profit over time of a hypothetical barnett shale gas well.

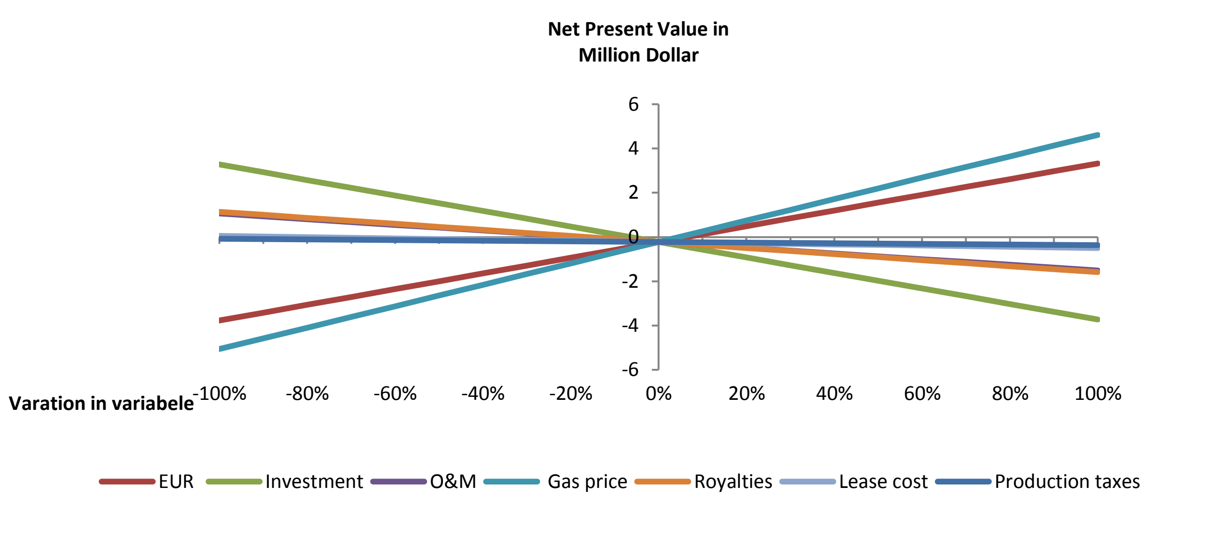


Figure 31 - Spiderdiagram of varying input parameters and the effect on the net present values.

4.3.5 Energy returns

An important factor when considering the production of energy is the Energy Return On Investment (EROI), a ratio which describes the amount of energy acquired to the amount of energy spent on acquiring the energy. If the EROI exceeds one, a net gain in energy is achieved. If the EROI becomes smaller than one it is uneconomical to produce the resource[29]. Fossil fuels tend to be energy-dense, indicating a high EROI. However, as the energy density of the resource becomes lower, in general more energy has to be spent to obtain the resource, leading to a lower EROI. In other words, over time depletion will tend to lower the EROI. Technological progress however can lead to more efficient ways of producing a resource and therefore a higher EROI. The EROI is therefore a dynamic parameter which changes over time.

The EROI of natural gas production peaked twice in the United States, at first during the seventies which corresponded with the peak of conventional natural gas production. In the years after the peak (1971-1982) it is most likely technology was not able to keep up with the decline in production, shown by decreased gas production despite a fourfold increase in the numbers of wells drilled (Sell et al., 2011). Increased research into unconventional sources of gas and rising gas prices during this period drove innovation, which led to the development of offshore gas fields and a rise in EROI. As the share of unconventional gas increased in the total gas production, the EROI approached a second peak in 1993 (Sell et al., 2011). After that, the EROI of natural gas has been declining, showing that increased drilling efforts and costs where necessary to obtain the same gross withdrawals per well. The reason for this decline is most likely the same as in the seventies: technological progress has not yet found a way to keep up with a decline in production, and little new types of resources have been unlocked besides shale reservoirs. Shale technology is still relatively new and changes in production and drilling cost could dictate future trends of the EROI (Sell et al., 2011)

[29] It might still make sense to extract the resource if the produced energy is in a more desirable form or if it can be converted to an energy carrier with an artificially inflated high price. Examples of this can be found in the Coal-to-Liquid conversion applied in Germany during World War II or the profitability of coal-to-liquids during historical high oil prices.

The EROI is strongly correlated to the EUR of the well since most of the energy used is invested upfront in the drilling process. Uncertainties with respect to the EUR reflect therefore also into the estimates of the EROI. At the moment no peer-reviewed studies exists for the EROI of shale gas. The best estimate comes probably from the preliminary results of a study done by Aucott & Melillo (2013), which will serve as the basis in this thesis with respect to the EROI. In this study the authors calculated the EROI for natural gas extracted from horizontal hydraulically fractured wells in the Marcellus shale. In the study, an EUR of 3 bcf was used which was derived from a curve fitting one year old production data from 343 wells[30]. The EROI was calculated with the following formula (Eq. 2):

$$EROI = \frac{(P-s)}{(wdc+sc+cc+en+scp+cp+br+wwt+etd)} \qquad \text{(Eq. 2)}$$

$Where$:	*Average value*
$P = EUR$	(2.98×10^{6} GJ)
$s = selfuse\ of\ produced\ gas\ for\ processing\ and\ compression$	(8.2%)
$wdc = energy\ used\ in\ well\ drilling, fracking, completion\ and\ transportation$	(9073 GJ)
$sc = embedded\ energy\ of\ steel\ used\ for\ casing$	(3874 GJ)
$cc = embedded\ energy\ of\ cement\ used\ for\ casing$	(1070 GJ)
$en = embedded\ energy\ of\ engines\ used\ onsite$	(907 GJ)
$scp = embedded\ energy\ of\ steel\ and\ energy\ used\ for\ pipelines$	(9637 GJ)
$cp = embedded\ energy\ of\ chemicals\ and\ proppant$	(4416 GJ)
$br = energy\ used\ over\ lifetime\ of\ well\ for\ brine\ removal$	(1177 GJ)
$www = energy\ used\ for\ wasteater\ treatment, including\ transportation$	(2706 GJ)
$etd = electricity\ used\ for\ transmission\ and\ distribution\ of\ produced\ gas$	(3870 GJ)
Total input =	36 731 GJ

Equation 2 shows that the EROI is directly proportional to the EUR and that calculated EROI's can therefore easily be scaled. The method used calculates the net external energy ratio (NEER), since self-use of gas is not incorporated as an energy input (only as a decreased output). Another way of calculating the EROI is displaying the refined output of a fuel to society in the numerator and all the energy inputs, including self-use, in the denominator. This net energy ratio (NER) resembles the total energy return in a system and will therefore be more useful in environmental assessments with respect to the emissions of GHG (Brandt & Dale, 2011). However, the NEER is a more useful method when assessing the potential from a societal point of view since it shows the amount of external energy needed in the process to supply a certain amount of energy (Brandt & Dale). Comparing the values of NEER and NER can give an indication of the extent of self-fuelling in energy production. If the NEER >>NER, then the process fuels itself to a large extent (Brandt & Dale, 2011). Values used for the energy embedded in steel and construction of pipelines seems to be the least certain. In addition to that, the energy used in the well drilling, fracking, and well completion and energy inputs in wastewater treatment are quite uncertain. This constitutes more than half of the total energy input. Using average values for the input ranges mentioned in the literature, the EROI becomes 81 : 1 (NEER). In order to deal with uncertainty, a Monte Carlo analysis was performed which produced a mean value of 85 : 1 with 10th and 90th percentiles of respectively, 64 : 1 and 112 : 1. When calculating the EROI with an EUR as estimated by the EIA at 1.56 bcf per well the NEER becomes 42 : 1. The NER gives an EROI of 8.0 : 1 to 11.8 : 1. This indicates that shale gas extraction is to a large extent self-fuelled. In Figure 32 several EUR's of other energy carriers are displayed as collected by a literature survey by Murphy & Hall (2011). Differences in methodologies used for calculating the EROI are not always clear and can account for variations in the EROI.

[30] Note that the EIA estimates an average of 1.56 Bcf/well for the EUR (see table 4) (EIA, 2012e).

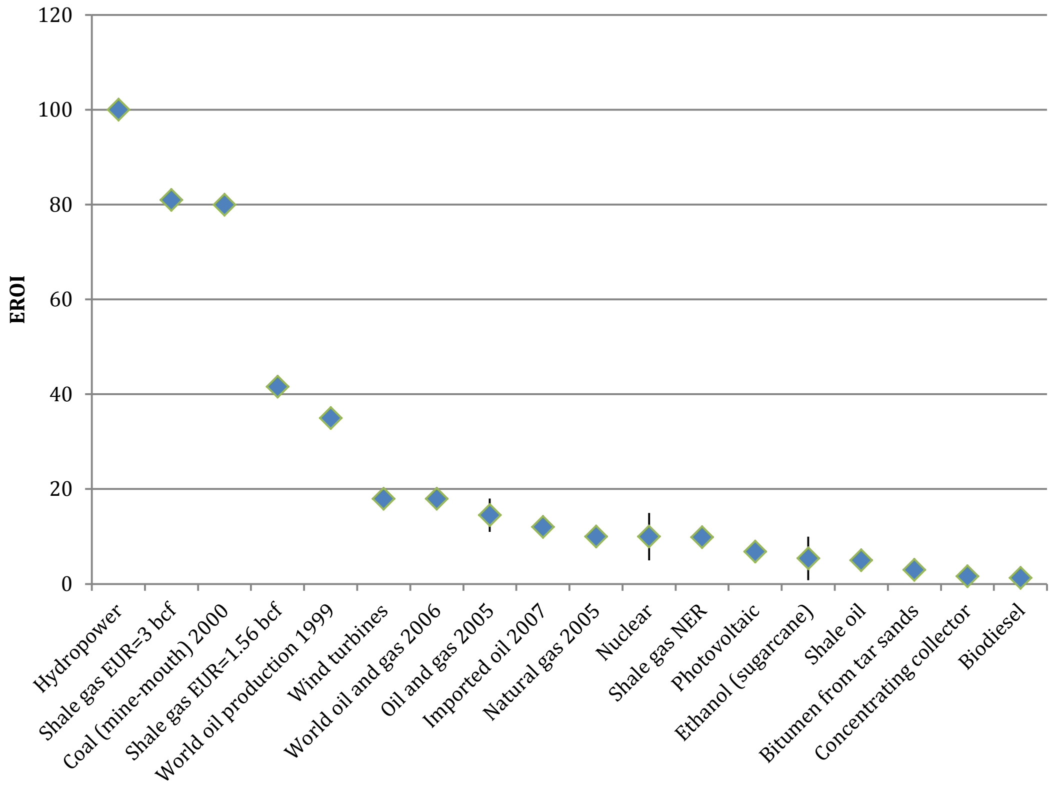


Figure 32 - EROI of various fuels for the United States unless otherwise specified. If a range of values was given for a fuel, the median value was presented along with the range. For shale gas the NER and NEER are displayed along with two EUR values for which the NEER was calculated. (Data from: Aucott & Melillo, 2013; Gagnon et al., 2009; Murphy & Hall., 2011)

Preliminary results show that shale gas has an EROI in the same range as coal, and much higher than conventional natural gas in the United States. Even with a lower EUR as used in the study, shale gas still outperforms most other energy technologies. Therefore, the relative high value of the EROI presented here may need some context. Conventional natural gas production has been in decline in the United States and global estimates for the EROEI of natural gas are higher than the natural gas value presented for the United States in figure 28 (Gagnon et al., 2009). Other values for the EROEI for natural gas are usually presented as an average value of oil and gas due to the associated nature of the resource. The global oil and gas EROI was estimated at 18 : 1 for 2006 (Gagnon et al., 2009). It is expected that the EROEI of conventional natural gas is higher compared to oil and that it should therefore exceed the ratio of 18 : 1 (Gagnon et al., 2009). In addition, differences in approach can lead to large differences in EROI, as seen in the difference between the NER and NEER. Other methods of calculation for EROI consist of calculating the average energy intensity per dollar in an economy and extrapolate this to an EROI by using the yearly investment in gas production along with yearly output of gas. Consistency lacks in the approach of calculating the EROI and future research should provide additional estimates to the value presented here.

4.4 Land use

Conventional natural gas originates in the source rock, migrates upwards over time and accumulates in traps in which a well is placed to produce the gas. Conventional gas fields are therefore scattered over the landscape since they rely on a trap in order for the gas to accumulate. Shale gas is a source rock and therefore shale gas is, in contrast to natural gas, present continuously throughout the formation. This means shale gas development relies on a large number of wells to extract the gas as ultimately every feasible part of the source rock needs to be fracked in order to realize the total potential a shale basin has (see Figure 33). Next to the placement of the well, additional supporting facilities have to be built to process the gas as well as the waste products, along with roads to allow easy access to the location. This spatially intensive development is reason for concern, as it could lead to an industrialization of the landscape and its associated problems. Recent advancement in technology such as drilling multiple wells from one location and longer lateral lengths can reduce the footprint of shale gas development, especially since supporting infrastructure only needs to be built once, but nevertheless drilling activities are expected to be significant.

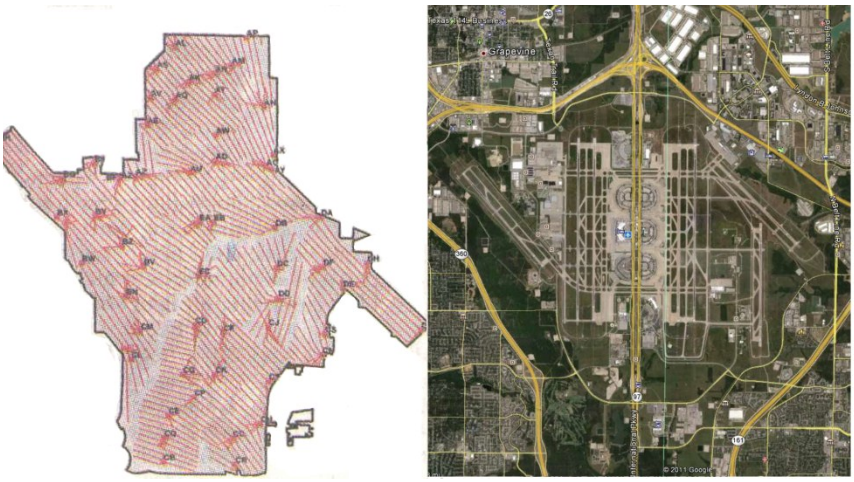


Figure 33 - Left: Development plan of Chesapeak Energy Inc. for shale gas production at Dallas Fort Worth Airport, Texas, US. Red dots represent well pads, red lines represent wells. In total 53 pads with 330 wells on an area of 78 km^2 can be seen. Right: Satellite image of Dallas Fort Worth Airport. (Ingraffea, 2011)

Well spacing can be defined as the maximum area that can be efficiently and economically drained by one well (Keuengoua et al., 2011). Typical well spacing a in conventional gas fields in the United States is 0,38 well/km^2, when shale gas development started in the Barnett shale typical well spacing was 1,5 well/km^2. Later so called "infill drilling" was permitted, drilling wells between producing wells to enhance productivity, leading to a well spacing of 6 wells/km^2. At the end of 2010 average well density in the Barnett shale was 1.15 wells/km^2, resulting from 15 000 drilled wells over an area of 13 000 km^2. (Lechtenböhmer et al., 2011) As shale gas developments continue, this well density will probably rise, apart from the drilling of more wells, due to increased infill drilling in new operations.

The EIA estimates that 18% of the Marcellus shale area might be suitable for shale gas extraction. This equals an area of ~48 000 km^2 [31]. Based on average well spacing in the Marcellus at the moment (1.93 well/km^2) this could lead to the drilling of ~90 000 wells in this area (EIA, 2012e)[32]. If the same calculation is applied to all the shale basins in the United States, a total of 410 722 wells need to be drilled in order to develop the potential areas. (EIA, 2012e) This does not account for potential shifts in well spacing due to increased infill drilling or advancements in technology.

[31] In 2010 99% of the area remained untested. (EIA, 2012e)

[32] The area of the Netherlands is 41 543 km^2

The average well pad consists of 1,6 – 2 hectares during the drilling and the fracturing phase. After that, less onsite equipment is needed and the well pad can be reduced to 0,4-1,1 hectares. (Lechtenböhmer et al., 2011).

The Groningen gas field has until now been produced with 296 gas wells concentrated in 29 locations dispersed over an area of 860 km^2 (Herber & Jager, 2010). The well spacing can thus be calculated at 0,03 well/km^2 which has led to a cumulative production of 2087 billion cubic metres (bcm) of gas (79 EJ)[33]. The EUR per well can therefore be estimated at 7 bcm or 0,26 EJ. With an average EUR of 44 million cubic metres (1,68 PJ) of a Marcellus shale gas well, a total of ~47 000 wells would have been necessary to produce an equal amount of gas as the current cumulative production of the Groningen field (EIA, 2012e). It should be noted though that the Groningen field is of exceptional quality: smaller fields in the Netherlands often have an EUR of 0,5-1,5 bcm which is still large compared to shale gas wells (Herber & Jager, 2010). The total amount of production wells constructed in the history of oil- and gas production in the Netherlands amounts to 1764 (NLOG, 2012). **Table 2** displays the amount wells necessary if all the shale gas resource estimates for the Netherlands would be developed with current EUR's for a Marcellus shale well and a highly productive Haynesville shale well.

Table 9 – Well count necessary for the production of the Dutch shale gas resource base assuming the EUR of a Marcellus shale gas well and a Haynesville shale gas well. (EUR from: EIA, 2012e)

Shale gas resource estimate NL	EUR Marcellus (44 Mm^3 - 1,68 PJ)	EUR Haynesville (75 Mm^3 - 2.88 PJ)
EIA (2013)	16 666	9737
TNO (2012)	4 488 – 11 214	2622-6552
Herber & Jager (2010)	226 - 446	132-260

[33] Local well spacing could be higher due to the concentrated areas of production.

5 The TIMER model

The TIMER model is used to assess how the increased availability of gas could impact the energy mix, energy trade and the effectiveness of climate policy. Several scenarios are constructed with different assumptions made regarding the availability and the prices of both conventional and unconventional gas. Main storylines consist of cheap unconventional gas restricted to North America and cheap unconventional gas present in the whole world for a world with and without the 450 ppm CO2 climate target reached by 2100. A quick overview of the complete TIMER model and the main dynamics is given followed by a more in-depth explanation of the relevant model parts and the implemented modifications. Results are discussed in Chapter 6.

5.1 General model overview and common elements

The Targets IMage Energy Regional model (TIMER) is an energy model used in combination with the Integrated Model to Assess the Global Environment (IMAGE) where the model can be used both as an integrated component as well as a standalone version (De Vries et al., 2001). Targets of analysis include long term dynamics in the energy system such as the transition to non-fossil fuel use and the development of energy related greenhouse gas emissions (De Vries et al., 2001). The TIMER model distinguishes between 26 world regions and the main exogenous drivers of the model are population and economic activity. The TIMER model consists of several submodels directed at calculating energy demand, energy supply and energy conversion (Van Vuuren, 2007). A schematic overview of the TIMER model can be seen in Figure 34. Economic and demographic indicators lead to a useful energy demand for the five different sectors. This useful energy demand can be supplied with secondary energy carriers which consist of refined fossil fuels, biomass, hydrogen, electricity or secondary heat. Allocation of the market shares is done on the basis of costs by means of a multinomial logit function. The secondary energy demand can then be translated to a primary energy demand via the energy conversion sub models. Emissions due to, for example, energy production, are accounted for. The model runs over the period 1971-2100 and is calibrated with historical data up to 2005.

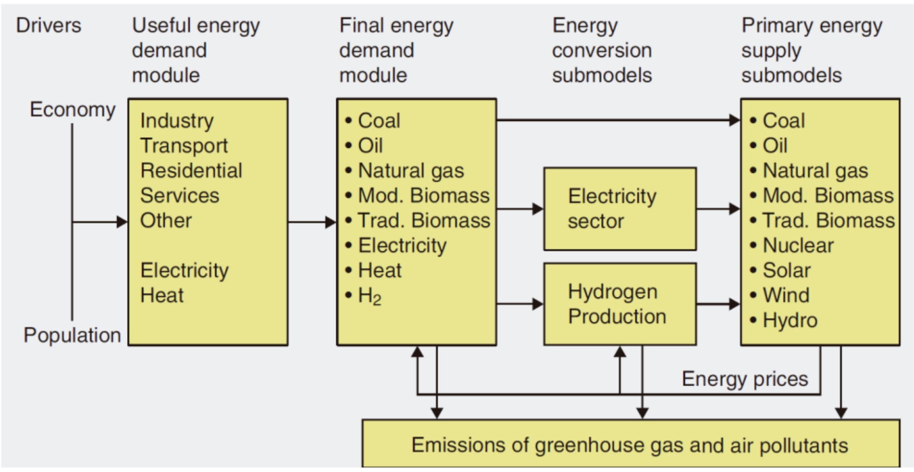


Figure 34 - Schematic overview of the TIMER model (Van Vuuren, 2007)

5.1.1 Multinomial logit

A central component in the TIMER model is the previously mentioned multinomial logit function which allocates market shares of the various fuels and technologies based on the relative costs and a formulation of substitution elasticity (see Eq. 3).

$$IMS_i = \frac{e^{-\lambda c_i}}{\sum_j e^{-\lambda c_j}} \qquad \text{(Eq. 3)}$$

The formulation shows the Indicated Market Share (*IMS*) of a certain fuel or technology *i* which is determined by the logit factory (λ) and the price (c) of that fuel or technology. This is compared to the price and logit factors of other fuels or technologies upon which relative market shares are determined. The parameter λ determines the influence of the costs of the fuel on the market share, small values of λ lead to inelastic market shares and vice versa (De Vries et al., 2001).

5.1.2 Technological progress and depletion

Another common component of the various sub-models is technological learning. This describes the trend of achieving cost reductions as a technology matures due to learning-by-doing. Learning-by-doing is formulated by a progress ratio which indicates the relative cost reduction as the cumulative output of a technology doubles (Van Vuuren, 2007). In the TIMER model, learning-by-doing influences the Capital Output Ratio (COR) of fossil fuel supply technologies, i.e. the amount of capital needed (expressed in monetary terms) to produce a certain amount of energy. Additionally, learning-by-doing applies to the investment costs of renewable and nuclear technologies as well as the costs of energy conservation (Van Vuuren, 2007). Technological learning can be subjected to knowledge-transfer between regions. In TIMER it is generally assumed that a global knowledge pool exists which regions can access, however it is possible to construct scenarios in which a regional access is blocked from this knowledge pool, after which learning-by-doing becomes dependent on the cumulative production within a region.

Furthermore depletion dynamics are included in various part of the model. Depletion dynamics describe the increase in supply cost of an energy carrier as a result of increased cumulative production. This can be imagined in the case of fossil fuels as the depletion of easily accessible low cost reservoirs which requires a shift to more complex or less favourable reservoirs and the resulting lower monetary returns due to e.g. increased investment costs per unit produced energy. The same dynamics can be imagined for renewable sources where they can apply to, for instance, the decreased availability of the most favourable sites for the placement of wind farms as production levels increase. Depletion dynamics are mimicked by the implementation of long term supply cost curves which describe increasing production costs for higher cumulative production.

5.1.3 Trade

Next to that regional interactions are modelled to reflect which regions can trade energy with each other. Allocation is done on the basis of production and transportation costs. Regions compare domestic production cost with the production cost in other regions along with the transportation cost, after which regions decide whether it is more advantageous to produce their own resources or whether to import them. Generally speaking, every region can trade with every other region, but it is possible to induce trade barriers between regions. Transport costs are calculated based on km-dependent costs and in some cases investment costs. Oil- and coal transport is done by ship and natural gas transport can be done either by pipeline or ship (LNG), in which LNG has higher investment costs but lower km-dependent costs. In practice, an approximate distance is found after which LNG transport is preferred above pipeline transport (~5000 km). A matrix describes the distance between the main ports of the various regions and an average value for intraregional transport. In cases of geographic barriers between regions (e.g. the Himalaya between China and India which would obstruct pipeline transport) the distance matrix is modified so that the correct mode of transport would be preferred by the model on a minimized cost basis.

5.1.4 Liquid/gaseous fuel supply model

The most relevant sub model for this thesis is the gaseous fuel supply model which is similar to the liquid fuel supply model. Figure 35 gives an overview of the fossil fuel supply models. The most important model elements are similar to the model elements described in the sections above.

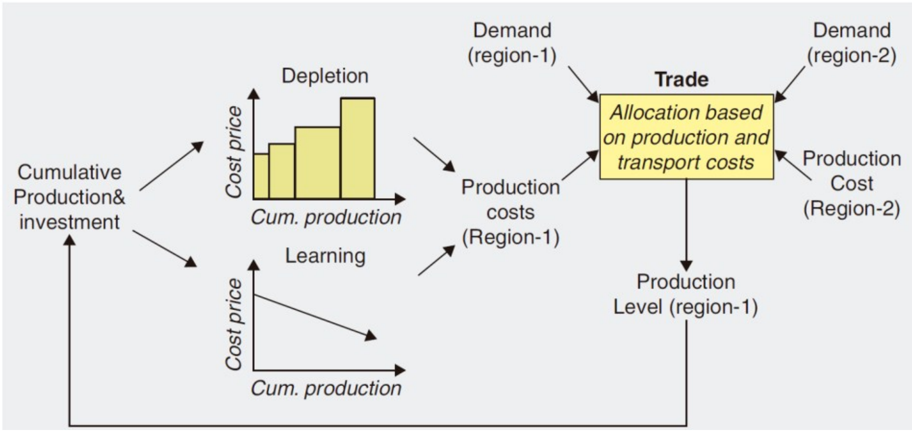


Figure 35 - Schematic overview of the fossil fuel supply model (Van Vuuren, 2007).

5.1.5 Investment and learning

Based on the regional production costs and the import costs, a region decides on its production level. This leads to the necessary investments, which are a function of the required capacity, the current installed capacity and the depreciation of capital. Several types of capital exist which all have their own capital output ratio: exploration capital, which converts resources into reserves; production capital, which converts reserves into primary energy; and refining capital which converts crude fossil fuels to refined products. Learning-by-doing lowers the COR ($/GJ) of the capital. For fossil fuels a progress ratio of 0.90-0.95 is used (De Vries et al., 2001).

5.1.6 Depletion

Depletion dynamics are simulated by categorizing the reserve and resource estimates according to the McKelvey box. This classification and the resulting definitions were used by Rogner (1997) in a comprehensive assessment of the world’s hydrocarbon resources, on which initial reserve and resource estimates in TIMER were based. These reserve and resource estimates have been updated by Mulders et al. (2006), who continued to use the same classification system.

The idea behind a McKelvey box (see Figure 36) is the fact that reserve and resource classifications are mainly dependent on two parameters: economic viability and geological certainty. Reserves are the share of the hydrocarbon resource base of which it is fairly certain that they are in place and that they can be produced at today’s international market prices with proven technologies. Various degrees of uncertainty are represented by classifying the reserves in different categories. Resources are classified as the share of the hydrocarbon resource base present in the Earth's crust which is potentially recoverable with respect to current or foreseeable future conditions. Again, a geological component is used differing between discovered or yet to be found resources. Finally, additional occurrences are represented which consist of the hydrocarbons that cannot be considered technically or economically viable (Rogner et al., 2012).

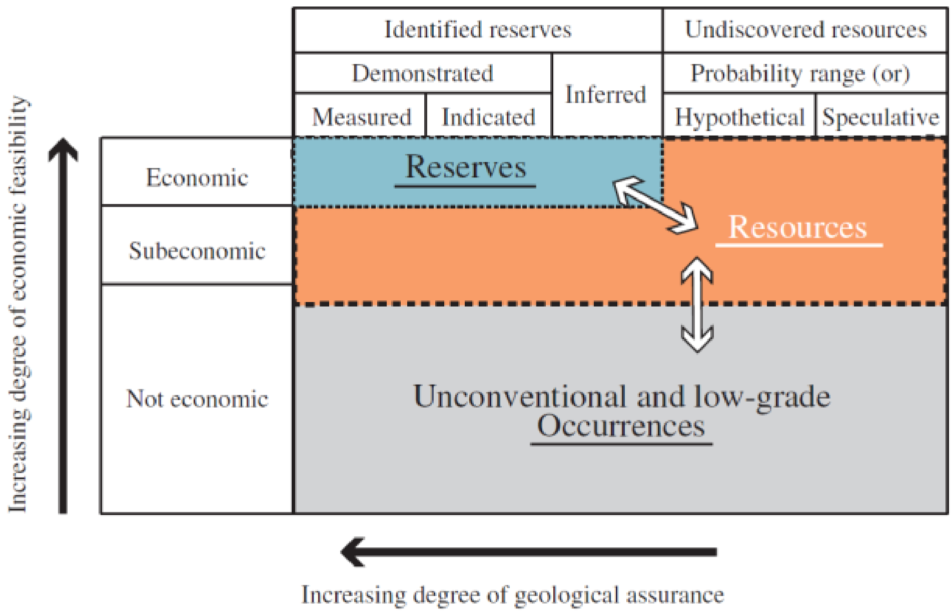


Figure 36 - Modified McKelvey Box as used by Rogner et al. (1997, 2012). (Rogner et al., 2012)

Rogner created eight categories along the axes of the McKelvey box for which the multiple definitions are used. These same eight categories, together with some additional categories for modelling purposes, are used in the TIMER model where each category has increasing production costs. A distinction is made between conventional (category 1-7) and unconventional (category 8-12) reserves and resources. Below are the definitions used to classify the resources. Table 10 shows the translation to the implemented categories in TIMER (Rogner, 1997; Mulders et al., 2006):

1. Proven recoverable reserves - Amounts of oil or gas in known reservoirs that are available for future extraction under current and expected local economic conditions with existing technologies.

2. Estimated additional reserves – Amount of oil or gas which is, based on geological and technical information, expected to be found and recoverable. For this category the United States Geological Survey (USGS) gives an optimistic (95% probability of being at least the expected amount), best (50% probability of being at least the expected amount) and pessimistic estimate (5% probability of being at least the expected amount).

3. Additional speculative resources – Comparable to category 2 but with a more speculative nature. Rogner et al. (1997) use the difference between the optimistic en median value, while in TIMER the difference between the optimistic and best estimate is used.

4. Enhanced Recovery – Additional oil and gas production from existing and abandoned reservoirs with advanced production techniques. For gas this category consists of 10% of the original in-situ amounts of conventional gas.

5. Unconventional recoverable reserves – Identified reserves of oil and gas that can be produced currently or in the near future against current international marketprices.

6. Unconventional resources – Comparable to category 2, in TIMER 20% of the expected recoverable resources are assigned to this category.

7. Additional unconventional resources – Comparable to category 6 but with an assignment of 35% of the expected recoverable resources.

8. Additional Occurrences – Comparable to category 6 but with an assignment of 45% of the resources plus all conventional and unconventional oil and gas which remain in-situ and which cannot be extracted. Methane hydrates make up a large part of this category. Hydrocarbons in this category are not expected to be technically or economically recoverable before the end of the 21st century.

Table 10 – Classification of TIMER categories compared to the classification used by Rogner (1997) along with the assumed recovery factor within TIMER.

	TIMER	Recovery factor		Rogner (1997)
1	Cumulative production 1970-2000	1		
2	Half proven recoverable reserves	1	1	Proved recoverable reserves
3	Half proven recoverable reserves	0.8		
4	Estimated additional reserves	0.7	2	Estimated additional reserves
5	Additional speculative resources	0.375	3	Additional speculative resources
6	Enhanced Recovery	0.5	4	Enhanced Recovery
7	Extra expensive category	0.7		
8	Unconventional recoverable reserves	1	5	Unconventional recoverable reserves
9	Unconventional resources	1	6	Unconventional resources
10	Additional unconventional resources	0.625	7	Additional unconventional resources
11	Additional Occurrences	0.625	8	Additional Occurrences
12	Extra expensive category	0.7		

TIMER introduces several model categories in addition to Rogner categories. These model categories have high prices which make them unattractive for production and they therefore prevent complete exhaustion of the resource base. Furthermore, TIMER does not assume that all resources can actually be extracted. Therefore it includes an expected recovery factor for each category. This recovery factor represents the percentage of the resources for which it is assumed they can be successfully extracted. Conventional and unconventional resources can be produced simultaneously where allocation of the produced type of gas is determined by multinomial logit dynamics.

5.1.7 Data sources for gas reserve and resource estimates in TIMER

As mentioned before, reserve and resource estimates in TIMER are based upon Rogner (1997) and were later updated by Mulders et al. (2006). The most extensive review of global conventional gas reserves and resources stems from the USGS (2000). This publication was the main source for Mulders et al. (2006). Unconventional gas reserve and resource data was not updated by Mulders et al (2006) due to limited new data availability. Therefore, current incorporated reserve and resource data is still based upon Rogner (1997).

5.1.8 Production cost in TIMER

Regional gas production costs in the TIMER model are simulated by a linear price movement throughout the depletion of a category where the initial price is the price of the previous category and the end price is the category-specific price. The initial production cost of the first category of the conventional gas resource base and the first category of the unconventional resource base are specified separately. To compensate for sudden price spikes at the depletion of a category, a smoothing function is introduced which dictates that the production costs are partly dependent on the production costs in the previous and in the next category. Furthermore, the production costs are multiplied with a learning factor which is determined by learning-by-doing within the model. A representation of the production cost dynamics within TIMER is displayed in Figure 37.

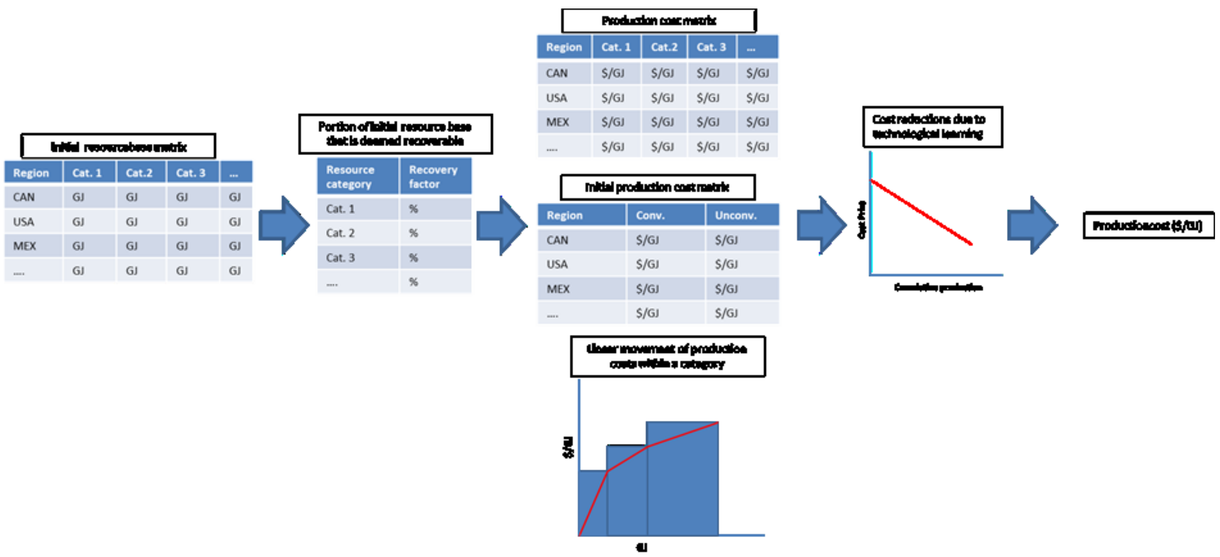


Figure 37 - Production cost dynamics within TIMER.

5.1.9 Climate policy in TIMER

In order to achieve the 450 ppm CO_2 target at the end of the century a carbon tax is introduced into TIMER. This means that in order an emission permit must be bought before CO_2 can be emitted to the atmosphere. As a result the price of fossil fuels rise and renewable energy technologies and carbon capture and storage (CCS) become more attractive. The price of the carbon tax is calibrated to the 450 reference scenario in such a way that the resulting emissions over the simulation period lead to a 450 ppm CO_2 concentration at the end of the 21st century.

5.1.10 Methane emissions

Emissions of various greenhouse gasses are calculated in TIMER for the several steps between the gas production and the end use. No distinction is made between conventional and unconventional gas. Methane emissions are accounted for during the production, the processing and the transportation of gas. Regional emissions factors are assigned for various time steps, which reflects changes in local practices, equipment quality and improvements over time. The formula for methane emissions during the production and transmission of gas is as follows:

$$EnEmisCH4 = \sum\nolimits_{R,EC} (1 - CH4enred_{R,EC}) * Enprod_{R,EC} * EFCH4prod_{R,EC} + (1 - CH4enred_{R,gas}) * GasSupply_R * EFCH4prod_R$$

Where:

EnEmisCH4 = Methane emissions from the energy industry
$CH4enred_{R,EC}$ = Regional reductions in methane emissions per energy carrier
$Enprod_{R,EC}$ = Regional production of per energy carrier
$EFCH4prod_{R,EC}$ = Regional methane emission factor for the productionstage per energy carrier
$GasSupply_R$ = Regional actual use of gas, local production + net trade
$EFCH4prod_R$ = regional emission factor for gas transmission

5.2 Model modifications

In the following sections the changes within the TIMER model made in this work are described. New gas reserve and gas resource data is based upon data presented by Rogner et al (2012) in the Global Energy Assessment (GEA). Production costs are based upon regional gas supply cost curves (SCC's) which were acquired through personal communication with Rogner. These curves were the basis for the aggregated global supply cost curve presented in the GEA (2012). Methane emission estimates during the production of unconventional gas are based upon Howarth et al. (2011).

Rogner et al. (2012) gives an update on unconventional gas reservoirs in the GEA 2012. Included in the reserve and resources estimates are several types of gas: shalegas, tight gas, coalbed methane and deep gas. Additionally, Rogner et al. (2012) gives an estimate of methane hydrate potential, a potentially vast resource which is highly uncertain in terms of technical or economic viability. Although reserve and resource definitions based on the McKelvey box were also used in gathering the data for the GEA 2012, separate estimates for the categories are no longer presented. Instead, a reserve and resource potential for the several types of unconventional gas is presented along with a theoretical, technical and economic potential for methane hydrates. In Table 11 the current reserve estimates incorporated in TIMER are shown along with the new reserve estimates by Rogner et al. (2012).

Table 11 - Resource estimates currently used in TIMER (update by Mulders et al., 2006), compared to more recent estimates by Rogner et al. (2012). Range for theoretical potential of methane hydrates is displayed for Rogner. Circum-artic included in the Rogner et al (2012) estimate for conventional resources. Methane hydrates are displayed separately due to their vast size and speculative nature. Since Rogner et al. (2012) does not present his data in different categories (only in reserve and resource format), TIMER categories are aggregated (category numeration according to Rogner (1997) (see Table 10). The recovery factor is incorporated in the TIMER estimates. (Rogner, 1997; Mulders et al., 2006; Rogner et al., 2012).

Global recoverable gas resources in EJ		Mulders et al. (2006)	Rogner et al. (2012)
Conventional gas	Reserves (cat. 1)	5851	5021
	Resources (cat. 2-4)	6858	7193
Unconventional gas	Reserves (cat. 5)	5652	20 156
	Resources (cat. 6-7)	20903	40 275
	Methane hydrates (cat. 8)	475 458	2496 - 2 772 889

As can be seen in Table 11, reserve and resource estimates for unconventional gas have increased considerably in the new estimates. Reserves have almost quadrupled, while resource estimates have doubled. The estimates for methane hydrates vary significantly in the new estimates. Figure 38 shows that the production cost of natural gas lay significantly lower in the new Rogner curves compared to the curve currently implemented in the TIMER model.

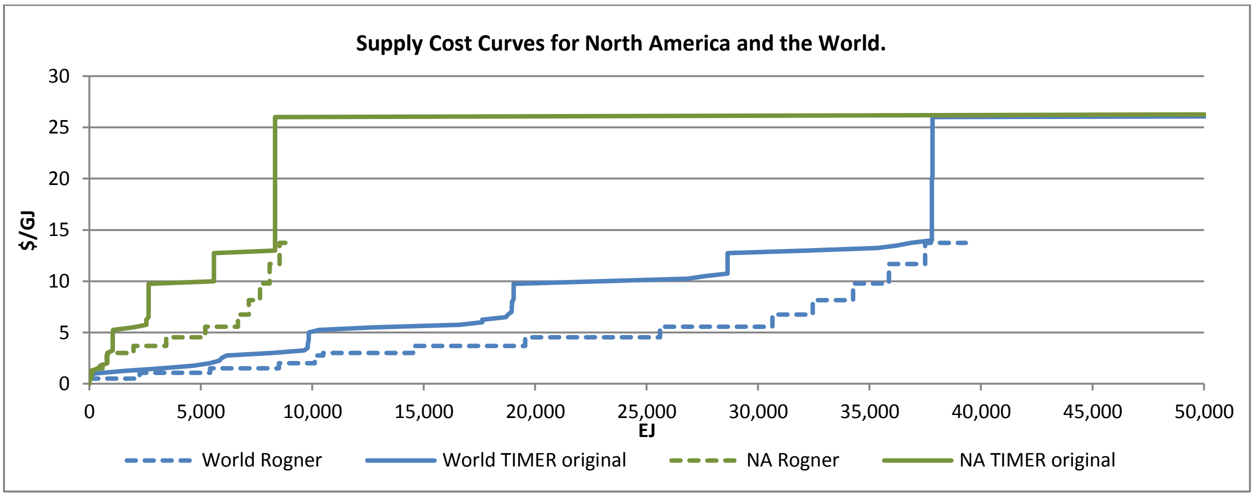


Figure 38- Natural gas supply cost curve in the original TIMER model compared to the supply cost curves from Rogner (2012) for North America (USA and Canada) and the World.

5.2.1.1 Unconventional gas resources

Rogner's supply cost curves only describe a part of the reserve and resource estimates presented in the Global Energy Assessments 2012. In the SCC all unconventional reserves (~20 000 EJ) and 20% of the unconventional resources (~8000 EJ) together with 5000 EJ of methane hydrates are incorporated. The resource base, however, is so extensive that, within the TIMER model, the remaining 80% of the resources would not be exploited in any scenario. Therefore, the methodology chosen reflects a change in the way current unconventional gas reserves and resources are portrayed in order to be able to better describe price differences present in the Rogner SCC. The unconventional reserves get their own class, while class 9 and class 10 both contain 10% of the resources included in the SCC. Class 11 contains all the remaining resources presented in the GEA but not included in the SCC. It is assumed that all the resources included in the Rogner SCC are producible and therefore the discovery factor is set to 1 for classes 8-10. Class 11 consists of 80% of the unconventional resources (32 220 EJ) and the methane hydrates (2496 – 2 772 889 EJ). Since a range is given and it is not clear to what extent the methane hydrates are actually producible it is assumed that roughly half of the maximum potential is producible and the discovery factor is therefore set to 0.5 for class 11. Class 12 is unchanged. Table 12 provides an overview of the new allocation of resources. To prevent natural gas production in the period where the model bases itself on historical data the discovery factor for the unconventional reserves is set to zero for the period 1971-2005, after that it becomes one.

Table 12 - Original allocation of unconventional resources to the TIMER categories and the allocation in this work.

Description	TIMER description (data: Rogner, 1997)	Discovery factor TIMER	This work (data: Rogner, 2012)	Discovery factor in this work
Class_8	Unconv. Reserves	1	Unconv. reserves	1
Class_9	20% of unconv. resources	1	10% of the unconv. resources	1
Class_10	35% of unconv. Resources	0.625	10% of the unconv. Resources	1
Class_11	45% of unconv. Resources + meth. hydr.	0.625	80% of unconv. resources + meth. hydr.	0.5
Class_12	Model category w/ high price	0.7	Model cat. w/ high price (unchanged)	0.7

5.2.1.2 Unconventional gas prices

Rogner presents different SCC's, distinguishing between gas supply costs in case only conventional gas was present and a curve in case of conventional and unconventional gas being present. Supply cost curves are constructed for each region of the 18 regions distinguished by Rogner. The price range ranges between 0.5-2.75$/GJ for conventional gas and between 3-13.73$/GJ for unconventional gas.

When comparing the curves with the unconventional resource estimates in the GEA it can be deduced that the production costs of unconventional gas reserves range between 3-5.55 $/GJ (see Table 13). The unconventional gas resources along with 5000 EJ of the methane hydrates are thus producible for 5.55-13.73 $/GJ.

Table 13 - Excerpt from the Rogner (2012) SCC data along with GEA gas reserve and resource estimates. (Note that only 20% of the unconventional gas resource estimates are included in the SCC).

Rogner unconventional part from the SCC's ($/GJ) (Cumulative resources)										GEA (2012)	
Region	3.00	3.70	4.54	5.55	6.76	8.15	9.78	11.66	13.73	Unconv. Reserves	Unconv. Resources
USA [EJ]	931	2,096	3,493	**4,657**	5,056	5,455	5,810	6,165	6,631	**4657**	8867
CAN [EJ]	238	537	894	**1,192**	1,288	1,383	1,468	1,553	1,667	**1192**	2124
WEU [EJ]	149	335	559	**745**	812	879	939	998	1,093	**745**	1490
EEU [EJ]	112	251	419	**559**	609	659	704	749	807	**559**	1118
…	…	…	…	…	…	…	…	…	…	…	…

Furthermore Rogner states in the GEA on the production cost of unconventional gas (Rogner et al., 2012):

"Production cost estimates vary considerably, from less than 2 $/GJ for shale gas from very permeable reservoirs, CBM, or onshore gas hydrate to more than 13 $/GJ for offshore deep gas reservoirs."

For this reason, it was assumed in this research that the unconventional gas reserves (class 8) had an initial production cost of 2 $/GJ and an upper boundary of 5.55 $/GJ. For class 9 the 10% of the unconventional resources was determined from the GEA after which the Rogner SCC was used to determine the upper price boundary of the resources. Class 11 incorporates the most costly producible unconventional resources and has an upper price boundary of 13.73 $/GJ. No production costs were available for the remaining 80% of the unconventional gas resources presented in the GEA so the production costs were left unchanged. Model category 12 has been kept in its entirety. Since input data in TIMER is specified according to the 1995 dollar value the production cost of Rogner had to be corrected for learning by dividing by a global deflator of 1.12. In addition, the starting year of the simulation in TIMER is 1971. The production cost input data therefore represents the production cost in 1995 nominal value at the start of the simulation and it needs to be corrected for technological learning. This was accomplished by dividing by the regional learning factors over the 1971-2005 period. Table 14 shows the new and the old input data.

Table 14 - Original unconventional initial production cost, upper boundary of a resource category's production cost along with reserve and resource estimates corrected for inflation and learning.

Description	Prodcost_ini TIMER old USA (1995$/GJ)	Prodcost TIMER old USA (1995$/GJ)	Gasresource TIMER old USA [EJ]	ProdCost_ini This work USA (1995$/GJ)	Prodcost This work USA (1995$/GJ)	Gasresource This work USA [EJ]
Class_8	5	6	582	2.18	6.04	4657
Class_9		10.81	1164		8.87	887
Class_10		14.09	1746		14.95	887
Class_11		28.75	191555		28.75	129221
Class_12		46	349		46	349

5.2.1.3 Conventional Supplies

Current conventional supplies in TIMER are based upon a variety of sources such as Rogner (1997), USGS (1995, 2000) and MNP estimates. Accounting for the incorporated recovery factor in TIMER, conventional reserves amount to 5851 EJ and conventional resources amount up to 6858 EJ (excluding the model category). Gas reserves and resources in the Rogner (2012) supply cost curves are based upon the USGS (2000; 2008) estimates. These USGS estimates are presented in the GEA where conventional reserves amount to 5021 EJ and resources (excluding the circum-arctic) up to 5445 EJ[34]. This means there is a slight excess of available resources in addition to a difference in regional distribution of resources in TIMER. Especially the United States seem to have an excess of reserves in the TIMER model (see Figure 39). Mulders et al. (2006) state that proven recoverable resources are extracted from Rogner (1997) and MNP and report 147 EJ for proven recoverable reserves in the United States and 55.7 EJ for Canada in TIMER. Rogner (1997) estimates that North America (Canada and the United States) hold 11.8 Gtoe (494 EJ). These regions account for 234 EJ of recoverable reserves in the GEA 2012. Other sources report between the 258-262 EJ for the United States (BP, 2010; BGR, 2009). In TIMER for the United States alone a total of 735 EJ of proven recoverable reserves are incorporated: it is not certain where this high number of proven

[34] Circum-arctic 1748 EJ.

recoverable gas reserves comes from since it is not comparable to the reports it should be based on. This number was therefore revised to the USGS (2000) estimates used by Rogner (2012). For Oceania (OCN) and Other Pacific Asia (PAS), a discrepancy was found between the Rogner supply cost curve data and the GEA 2012 data. Comparison with other sources shows a higher correspondence with other sources for the SCC's curves (see Figure 39). It was therefore assumed that these values were correct. For other regions the original TIMER reserve estimates were compared to a variety of sources. The reserve estimate was corrected in case a significant deviation of the USGS (2000; 2008) estimates used by Rogner (2012) occurred which could not be justified by variations in other sources.

Table 15 - Excerpt from the Rogner (2012) SCC data along with GEA gas reserve and resource estimates.

Rogner conventional part from the SCC's ($/GJ) (Cumulative resources)						USGS (2000;2008)	
Region	0.5	1.07	1.50	2.00	2.75	conv. Reserves	conv. Reserves + Resources
USA [EJ]	73	229	522	696	**732**	180	**732**
CAN [EJ]	18	41	59	73	**79**	54	**79**
WEU [EJ]	131	312	485	608	**657**	263	**657**
EEU [EJ]	9	20	30	37	**41**	26	**41**
…	…	…	…	…	…	…	…

Table 16 - Allocation of conventional resources to the TIMER categories along with the discovery factor.

Description	TIMER description (data: Mulders et al.,(2006) based upon: Rogner (1997), and USGS (2000)	Discovery factor
Class_1	Cumulative production	1
Class_2	Half reserves	1
Class_3	Half reserves	0.8
Class_4	Estimated additional reserves	0.7
Class_5	Additional speculative resources	0.375
Class_6	Enhanced Recovery	0.5
Class_7	Model category w/ high price	0.7

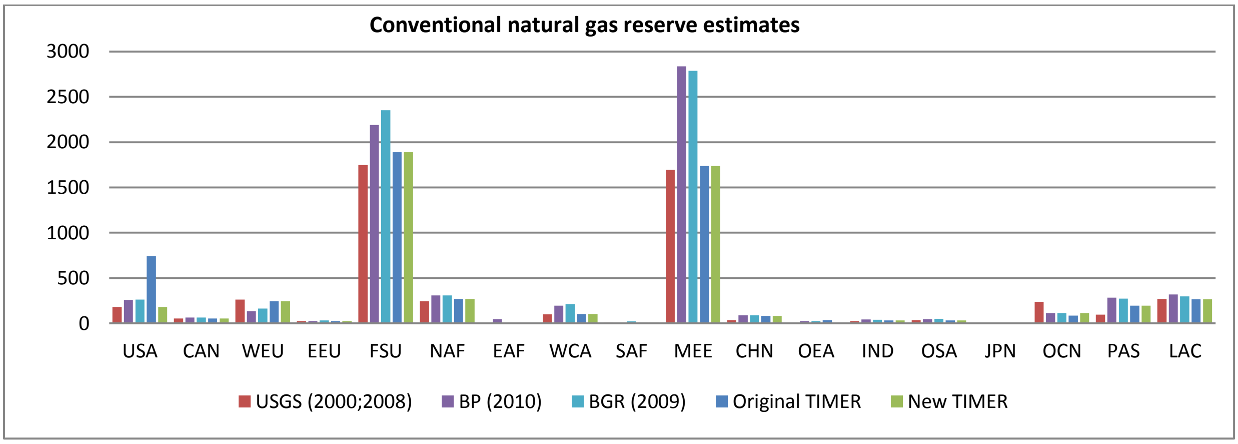


Figure 39 - Conventional gas reserve estimates from a variety of sources presented in the GEA 2012, the original TIMER model reserve estimates corrected for the discovery factor and the new values. (Rogner et al., 2012)

The production costs were acquired by using the Rogner (2012) supply cost curves and the new TIMER reserve estimates.

5.2.2 Methane

As Howarth et al. (2011) indicated, fugitive methane emissions during shale gas production could lead to a much higher emission factor than the GHG-footprint of conventional gas. Howarth et al. (2011) estimate that fugitive emissions of shale gas could amount to 3.6 -7.9 % of all the gas produced compared to 1.7- 6.0 % during conventional production (see Table 17). In TIMER, fugitive methane emissions are differentiated between the production-phase, the processing-phase and transportation and distribution stages. The value chain of shale gas and conventional gas does not differ much after the production stage and for this reason this is the only emission factor in need of modification. Howarth et al. (2011) mentions the similarities in shale gas and tight sand gas production and therefore also uses tight sand gas wells in their calculations.

Table 17 - Fugitive methane emissions associated with development of natural gas from conventional and shale development (percentage of fugitive methane over the total production). (Howarth et al., 2011)

Stage	Conventional gas well	Shale gas well
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total	1.7-6.0%	3.6-7.9%

The production stage in Table 17 consists of the emissions during well completion, routine venting and equipment leaks at the well site and emissions during liquid unloading. Methane emissions during well completion consist of dissolved methane in flowback water emitted into the atmosphere and emissions during the drilling of the plugs used to separate the various fracturing stages. Venting can be applied as a pressure relief mechanism and is incorporated in many onsite valves as a safety measure. Next to that, the multiple connections between the wellhead and the eventual pipeline will amount to some methane leakage. As wells mature they can start producing water which can clog the well, which therefore needs removal. In this process, called liquids unloading, the well head is often exposed to the air, leading to methane emissions. Howarth et al. (2011) assume that after the well head is connected to the on-site equipment, conventional production will not differ any longer from unconventional production. The only difference in emissions factor therefore occurs during the well completion. Since horizontal drilling and hydraulic fracturing is also applied to CBM wells and tight sand wells, it is assumed this increase in emissions is applicable to all the unconventional gas incorporated.

The methane emission factor in TIMER is specified as kg-CH4 emitted per TJ produced gas. Each region has a specific emission factor which is specified for several time steps. Over time, emission factors are reduced as a result of more utilization of the gas instead of venting and the application of cleaner technologies. In 2000 the methane emission factor of the United States for gas production consisted of 40 kg/TJ, which can be converted to a methane leakage of 0,22% of the total production[35]. Indonesia and the Middle East have the largest methane emissions during production, respectively 4.22% and 3.88%, which is probably due to the high degree of venting. Howarth et al. (2011) estimate a range of 0.31-2.17% for methane losses during the production stage of conventional gas and 2.21-4.07% for shale gas production (see Table 17). Consequently, for shale gas an additional 1.9% is added to the emission factor in the production stage. This way, regional differences in emissions factors continue to persist but the additional expected methane emissions are still incorporated. Figure 40 shows the original and the new unconventional emission factors along with the estimates of Howarth et al. (2011). Emission factors have been changed for 2000 and 2010. Since several technologies focused at capturing fugitive methane emissions (Reduced Emission Completion or REC) already ensure the emission footprint of shale gas does not differ from conventional gas it is assumed that at the end of the century (2100) conventional and unconventional emissions will again reach equality.

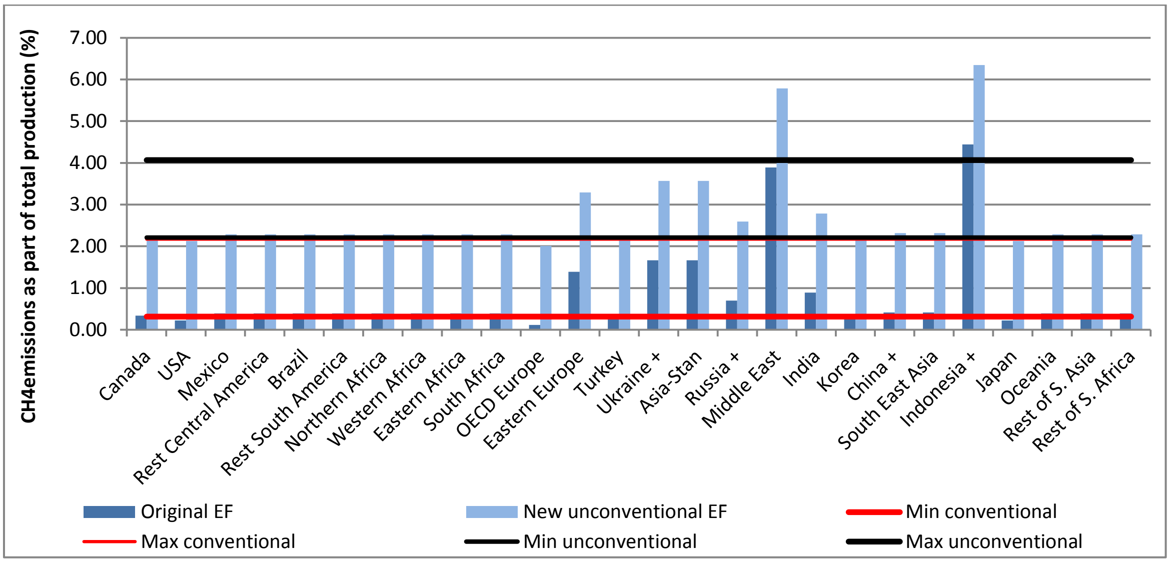


Figure 40 - Original methane emission factors (EF) during the production phase of gas and the new emission factors for unconventional gas. Solid lines represent the ranges Howarth et al. (2011) assigns to conventional and unconventional production.

The new formula for methane emissions in the energy industry due to natural gas use becomes:

$$EnEmisCH4_{R,gas} = \sum_{R} (1 - CH4enred_{R,gas}) * Enprod_{R,conv} * EFCH4prod_{R,conv} + (1 - CH4enred_{R,gas}) * Enprod_{R,unconv} * EFCH4prod_{R,unconv} + +(1 - CH4enred_{R,gas}) * GasSupply_{R} * EFCH4prod_{R}$$

Where:

$EnEmisCH4$	= *Methane emissions from the energy industry due to natural gas use*
$CH4enred_{R,gas}$	= *Regional reductions in methane emissions per energy carrier*
$Enprod_{R,conv}$	= *Regional production conventional gasproduction*
$Enprod_{R,unconv}$	= *Regional production unconventional gasproduction*
$EFCH4prod_{R,gas}$	= *Regional methane emission factor for the production stage per energy carrier*
$GasSupply_{R}$	= *Regional actual use of gas, local production + net trade*
$EFCH4prod_{R}$	= *regional emission factor for gas transmission*

[35] Methane has a combustion enthalpy of 891 KJ/mol and a molar mass of 16.04 g/mol. 40 grams of methane represents an energy content of 40 [g] / 16.04 [g/mol] * 891 [kJ/mol] = 2222 KJ or 2.22 * 10^{-3} GJ. Losses during the production can thus be calculated at 0.22% of the total production.

5.2.3 Regions:

Regions within TIMER differ from regions used in the GEA (see Figure 41). In order to be able to compare data the regional divisions had to be made comparable. If bordered regions fitted within a larger Rogner region, simple aggregation of TIMER regions was sufficient, e.g. in South and Central America and South Africa. Allocation of the resources located within a Rogner region was based upon land surface area. In some cases, similar regions had different borders; e.g. Sudan is incorporated in East Africa in the TIMER model whereas it is a part of Northern Africa in the GEA. In these cases portions of the reserves and resources would have been allocated according to surface area, assuming a uniform distribution of resources within a region unless specific information was available to indicate otherwise. For example, this was the case in North and South Korea. These countries are known to contain little to no gas resources, yet they would have gained a portion of the relatively rich PAS region if conversion was based upon surface area. Surface area data per land has been extracted from the CIA World Factbook (2013). Country-specific reserve and resource estimates, used to decide whether resources were available at all, were acquired from the at EIA (2013d). A complete list of the regional conversion can be found in APPENDIX C. TIMER regions

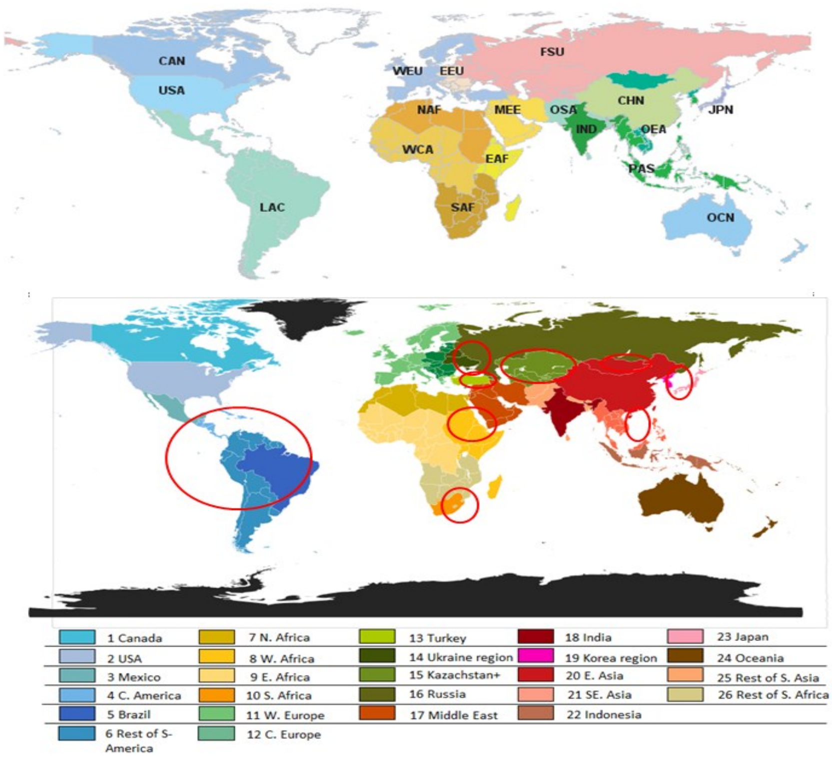


Figure 41 - Above: map of the regions used in the GEA. Below: map of the regions in the TIMER model. Differences are marked by red circles.

5.3 Scenarios

Six main scenarios were constructed in order to compare a world without climate policy and a world with a 450 ppm climate target. Various unconventional gas development pathways can then be compared. The scenarios are constructed on the premises that unconventional gas production might stay limited to North America or that it might progress to the rest of the world. A reference scenario consisting of the model in its current form functions as control. Furthermore the development pathways are compared for a world where a carbon tax is introduced calibrated to reach a 450 ppm CO_2 concentration at the end 21st century and a world without this carbon tax. Several variations on the scenarios are introduced with respect to updated conventional resources and prices and higher methane emission factors for unconventional gas. The main storylines then become:

Reference scenario

- Current TIMER model, no climate policy
- Current TIMER model, 450 ppm CO_2 climate target

North America scenario

- Unconventional gas resources and prices limited to the US and Canada, no climate policy
- Unconventional development limited to the US and Canada, 450 ppm CO_2 climate target

World scenario

- Unconventional gas development in the whole world, no climate policy
- Unconventional gas development in the whole world, 450 ppm CO_2 climate target

Scenario name	Carbon Tax	Unconv. gas resources and prices USA and Canada updated	Unconventional gas resources all regions updated	Conventional resources and prices all regions updated	Higher methane emission factor for unconventional gas
450 (reference scenario)	x				
450_NorthAm	x	x			
450_World	x		x		
450_Methane	x				X
450_NorthAm_Methane	x	x			X
450_World_Methane	x		x		X
450_AltConv	x			x	
450_NorthAm_AltConv	x	x		x	
450_World_AltConv	x		x	x	
450_AltConv_Methane	x			x	X
450_NorthAm_AltConv_Methane	x	x		x	X
450_World_AltConv_Methane	x		x	x	X
Base (reference scenario)					
Base_NorthAm		x			
Base_World			x		
Base_Methane					X
Base_NorthAm_Methane		x			X
Base_World_Methane			x		X
Base_AltConv				x	
Base_NorthAm_AltConv		x		x	
Base_World_AltConv			x	x	
Base_AltConv_Methane				x	X
Base_NorthAm_AltConv_Methane		x		x	X
Base_World_AltConv_Methane			x	x	X

6 Results

6.1 Global Primary Energy Production

Table 18 summarizes the results of the changes in global primary energy production due to the increased availability of unconventional gas. In general, substitution effects in the Base_NorthAm and Base_World scenarios will be more evenly distributed over all primary energy carriers, whereas in the 450_NorthAm and 450_World scenarios mostly fossil energy carriers are substituted which is not surprising. Natural gas seems substitute mostly for coal in all scenarios. In the following sections they are studied in more detail.

Table 18 - Share of energy carriers in primary energy production compared to the reference scenario over the simulation period 1971-2100.

Energy Carrier	450	450_NorthAM	450_World	Base	Base_NorthAm	Base_World
Coal	1.00	0.94	0.77	1.00	0.97	0.84
Conventional Oil	1.00	1.00	0.99	1.00	1.00	0.98
Unconventional Oil	1.00	0.99	0.94	1.00	0.99	0.85
Natural Gas	1.00	1.05	1.27	1.00	1.06	1.36
Mod. Biofuel	1.00	1.02	1.02	1.00	0.92	0.72
Trad. Biofuel	1.00	1.00	0.99	1.00	1.00	0.99
Nuclear	1.00	0.96	0.82	1.00	1.00	0.92
Solar / wind	1.00	0.99	0.96	1.00	0.98	0.93
Hydroelectricity	1.00	1.00	1.00	1.00	1.00	1.00

6.1.1 Base, Base_NorthAm and Base World

Figure 42 shows world primary energy use for the base-scenarios. Gas production in the abundant natural gas scenarios starts to deviate from the baseline in 2020. Over the simulation period, global natural gas use increases respectively with 6.5% and 35.8% in the Base_NorthAm and Base_World scenarios. The availability of additional unconventional gas resources seems to impact mostly coal production, mainly due to substitution in the electricity sector. In the Base_World scenario, the use of renewables is also visible lower compared to the baseline scenario[36]. This is caused for a large part due to gas substitution of modern biofuels, although solar and wind also experience some reductions in production. Nuclear and oil use is hardly affected by the increased natural gas supplies.

[36] Renewables= Solar/Wind, Hydro, Traditional biofuel, Modern biofuel.

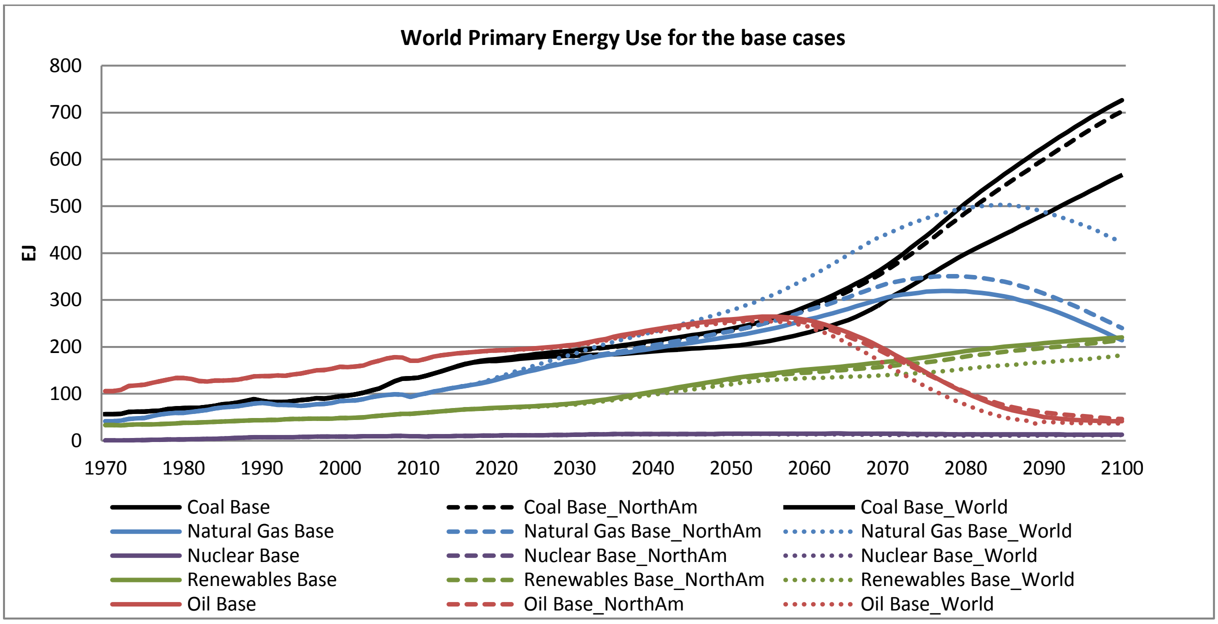


Figure 42 – Global primary energy use in the base case for the various energy carriers. Conventional oil and unconventional oil production are grouped together in oil. Renewables consist of traditional and modern biomass, solar, wind and hydroelectricity.

6.1.2 450, 450_NorthAm and 450_World

Figure 43 shows world primary energy use for the 450 scenarios. In the 450 scenarios coal substitution is even more fierce compared to the scenarios without climate policy. Also, nuclear is reduced more severely, with a 17% reduction in the 450_World scenario compared to the 450 reference scenario compared to only 8% reduction from the baseline scenario to Base_World. Natural gas does not gain as much share in 450_world scenario compared to the Base_World scenario due to a carbon tax which makes fossil production more expensive. When comparing the 450 reference scenario with the 450_World scenario substitution is almost exclusively for fossil technologies. The overall production profile seems similar to the reference scenarios. Figure 44 shows how the deployment of renewable energy technologies in the various 450 scenarios is hardly affected.

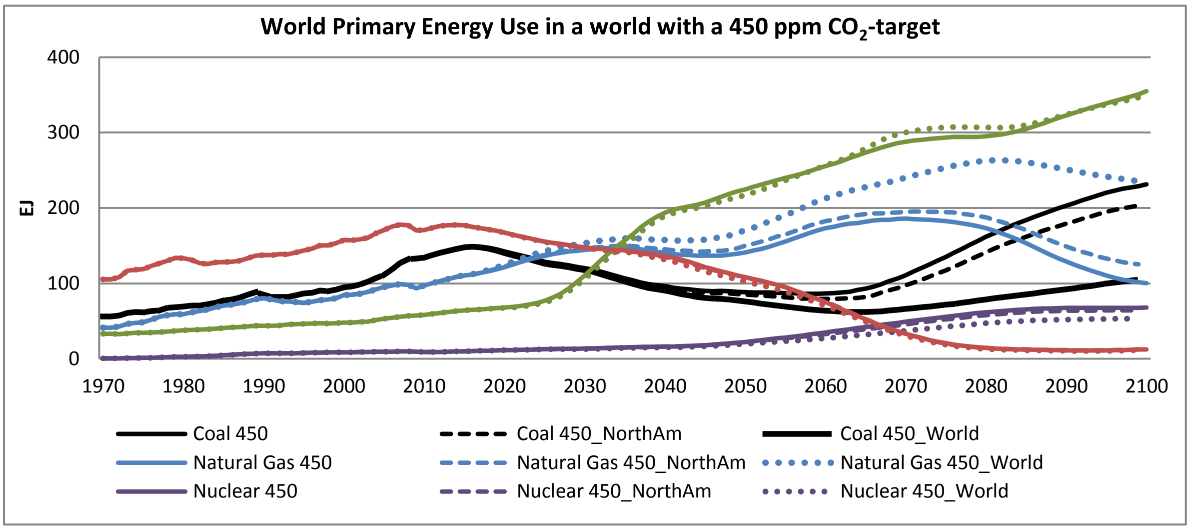


Figure 43 – Global primary energy use in a world with a 450 ppm CO_2-target case for the various energy carriers. Conventional oil and unconventional oil production are grouped together in oil. Renewables consist of traditional and modern biomass, solar, wind and hydroelectricity.

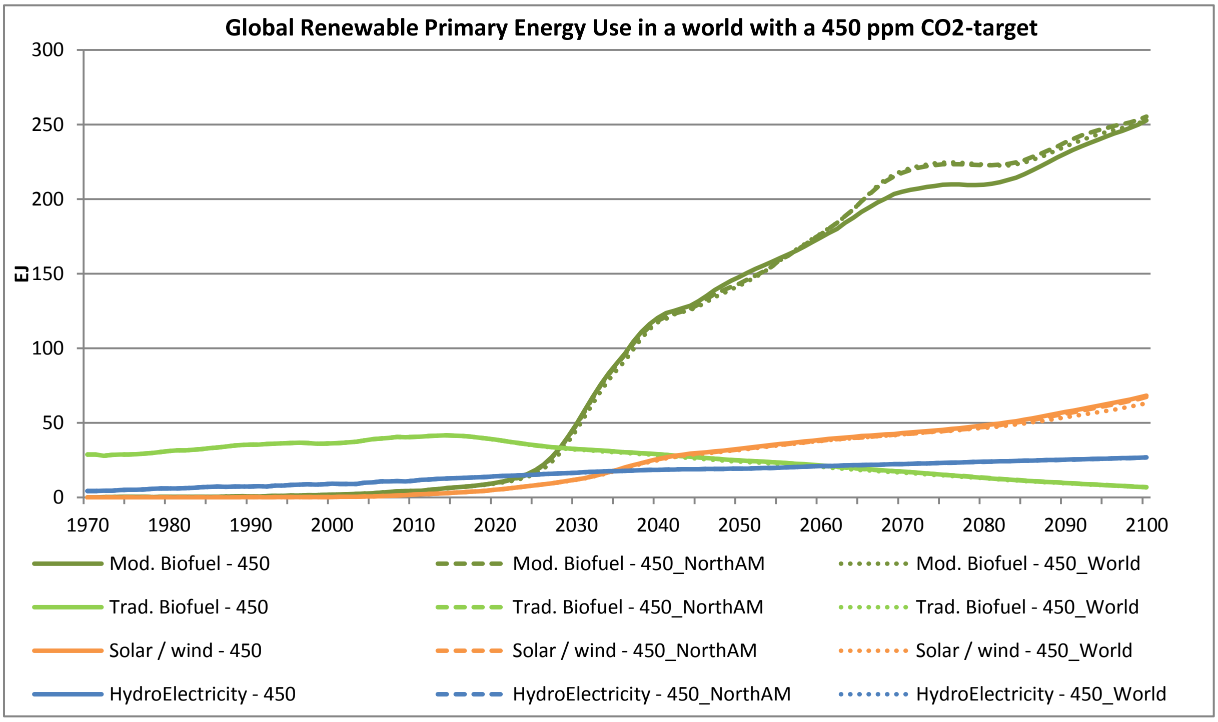


Figure 44 - Global renewable primary energy use in a world with a 450 ppm CO_2-target.

6.2 Conventional and unconventional gas production

6.2.1 Base, Base_NorthAm and Base_World

Figure 6 shows the division between global conventional and unconventional gas production. When comparing the reference scenario with the Base_NorthAm scenario, it shows that global conventional gas production is not very affected by this fact. Unconventional gas production starts to become competitive between 2020 and 2030 as conventional natural gas reserves are decline. Global unconventional gas production over the simulation period increases by 19.4%. The shape and the size of the unconventional gas production profile are slightly higher than in the original model but overall comparable. There is almost no substitution of conventional gas production. In the Base_world scenarios large differences can be seen, as unconventional gas production over the simulation period more than doubles with an increase of 113.7%. The resulting substitution of conventional gas supplies leads to reduction of 5.2% in conventional gas production.

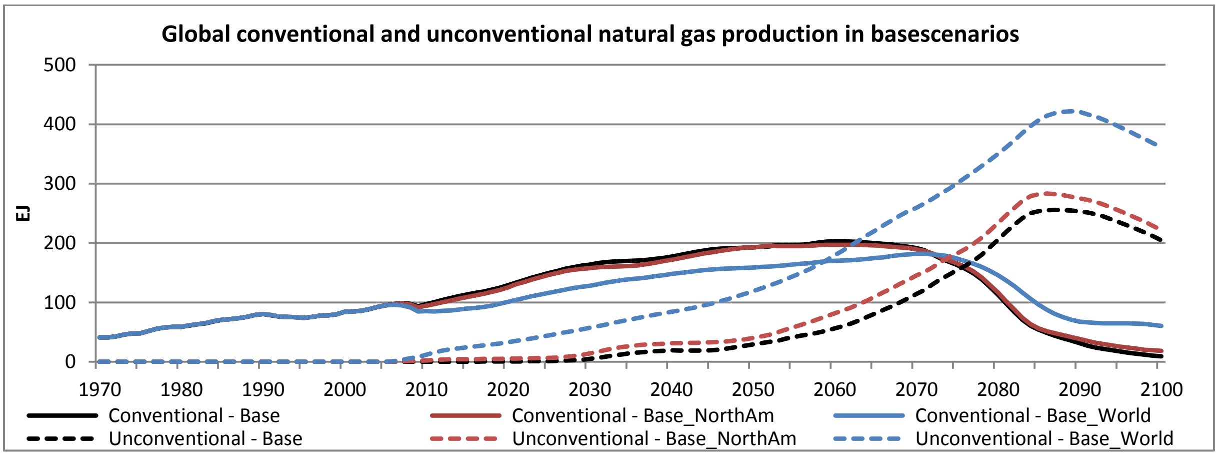


Figure 45 - World total of conventional and unconventional natural gas production for the base scenarios.

For the USA unconventional gas production in the Base_World scenario is lower compared to the Base_NorthAm scenario due to the reduced exports of gas. Substitution of conventional gas supplies is similar for the Base_NorthAm and the Base_World scenario. Although unconventional gas has a place in the energy mix from 2005 onwards, it takes until 2045 before production starts to increase fast as conventional gas resources are declining.

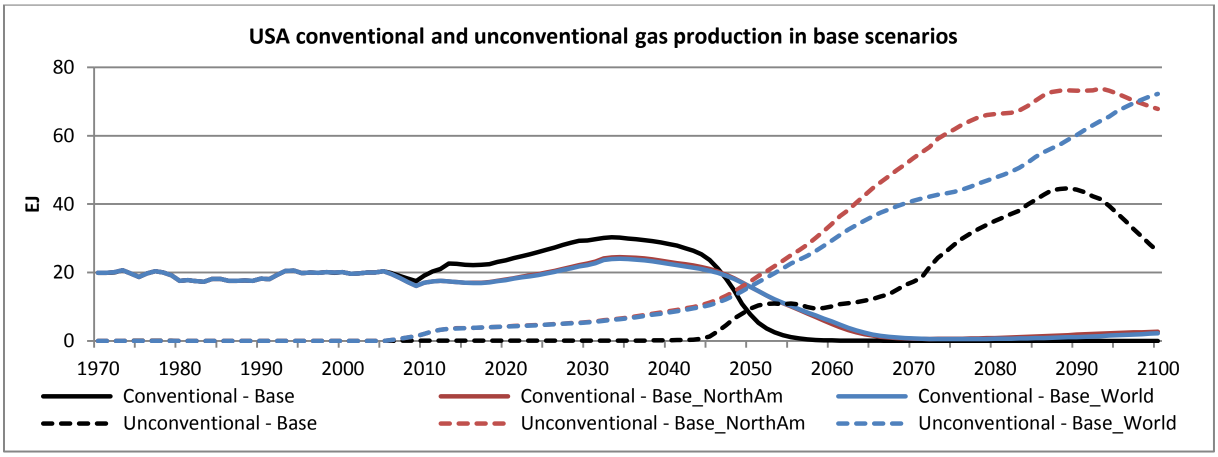


Figure 46 - Conventional and unconventional gas production in the USA for the base scenarios.

6.2.2 450, 450_NorthAm and 450_World

Error! Reference source not found. shows the division between global conventional and unconventional gas production. For the 450 scenarios, the growth in unconventional gas production is more fierce compared to the base scenarios. For the 450_NorthAm scenario cumulative global unconventional gas production increases by 43.4% where in the 450_World scenario cumulative unconventional gas production more than triples as it increases with 247%. In the 450_NorthAm scenario conventional gas production decreases only slightly with 1.5%, indicating the large increase in overall natural gas use. Conventional gas production in the 450_World scenario decreases with 11%. Where in the base scenarios unconventional gas production plateaus between 2015 and 2045, it continues to grow in the 450 scenarios.

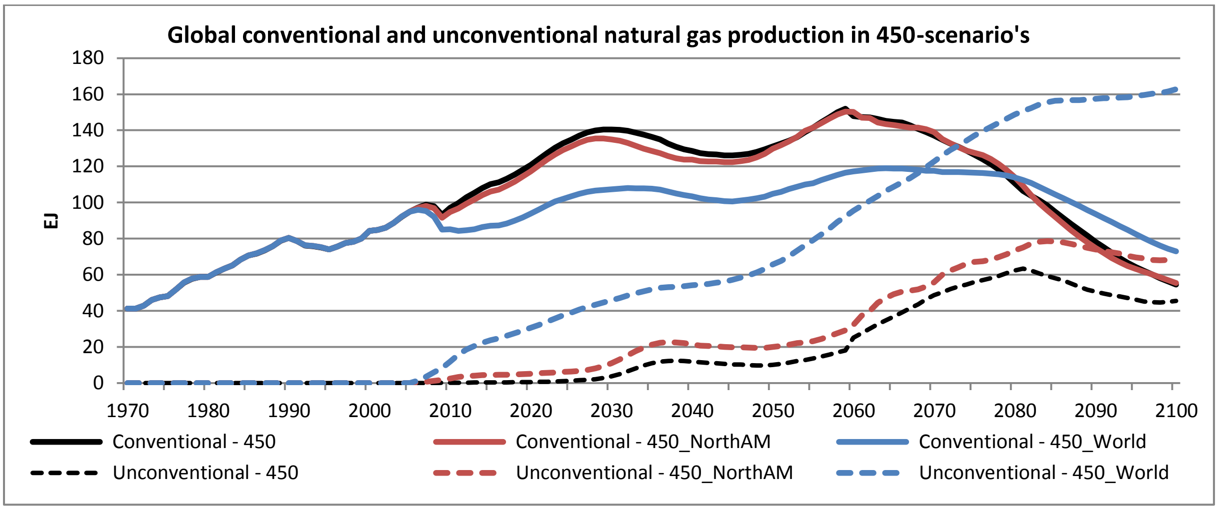


Figure 47 - World total of conventional and unconventional natural gas production for the 450 scenarios.

For the USA trends are visible which are similar to the base scenarios. Conventional gas production rates are lower at the peak but are more prolonged. Cumulative conventional gas production over the simulation period is therefore similar. Due to a reduced demand for US exports the unconventional gas production is lower in the 450_World scenario compared to the 450_NorthAm scenario.

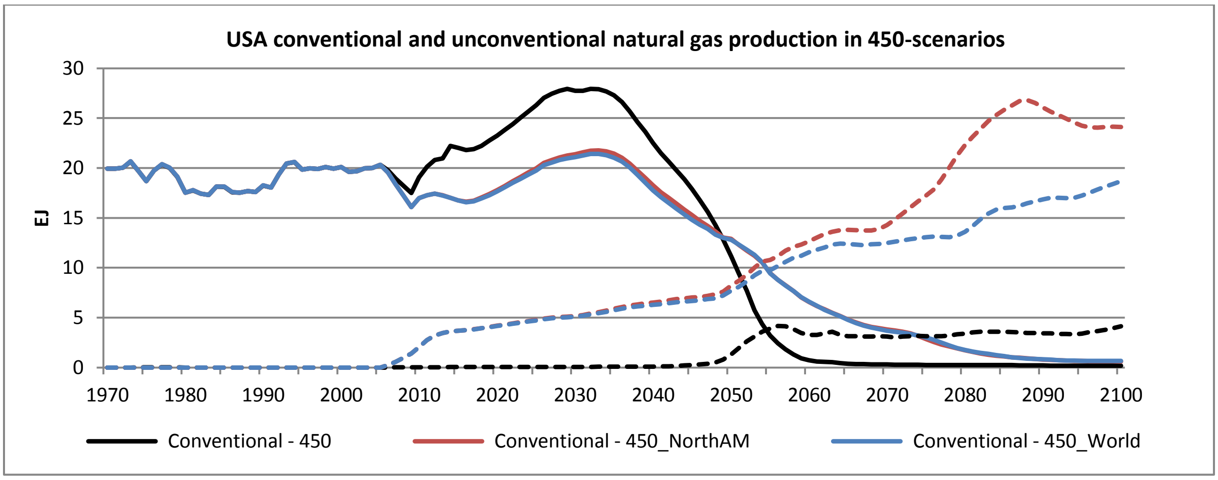


Figure 48 - Conventional and unconventional gas production in the USA for the base.

6.3 Regional gas production and gas trade

The main difference in the Base_NorthAm scenario seems to be caused by gas production in the United States. Both Canada and the United States increase gas production by a total of respectively 47.9% and 54.8%, but absolute production in the United States outweighs Canadian production. Increased North American gas production partly substitutes for regional gas production elsewhere as exports increase, although for most regions the difference in production is not very obvious. The biggest difference in production levels occurs in the Rest of South Asia, Turkey and Oceania where gas production levels fall by 9.6%, 7.9% and 7.7%. These reductions in production levels coincide with increases in natural gas imports, especially in the second half of the 21st century. When looking at absolute numbers, traditional natural gas exporters as Russia, the Middle East and Oceania have the largest reductions in production levels. Russia and the Middle-East alone account for more than a third of the drop in cumulative gas regional production outside North-America. This corresponds with a decrease in exports in the second half of the 21st century from these regions, indicating that North America captured some market share of the export market.

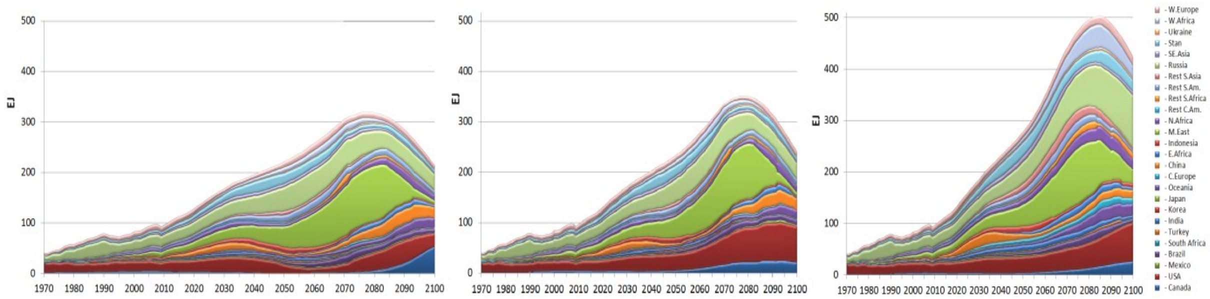


Figure 49 - Regional natural gas production, from left to right: Base, Base_NorthAm, Base_World.

In the Base_World scenario almost every region experiences increased natural gas consumption over the simulation period. Canada and the United States have lower production levels compared to the Base_NorthAm scenario, which can be expected due to their less favorable position in the natural gas export market (respectively 21.1% and 37.3% production growth over the simulation period compared to the baseline). South American gas production levels stay relatively stable compared to the baseline (varying between 96.5-108.7%). However, some countries who were formerly relatively small gas producers grow fast with the increased availability of unconventional gas. West-Africa, which has an equivalent unconventional resource base compared to Canada, grows massively. The same goes for Eastern Europe which holds very small conventional gas reserves and resources and is for the complete simulation period mainly dependent on Russia for gas-imports in the baseline. In the base_world scenario it becomes a natural gas exporter between 2030-2035 however, and it experiences a tripling in natural gas production over the simulation period. More traditional gas producers such as the Middle-East, Western Europe and Russia experience more moderate production growth over the simulation period of respectively 5%, 21% and 31%. Especially the Middle East has large conventional gas reserves which inhibit unconventional production.

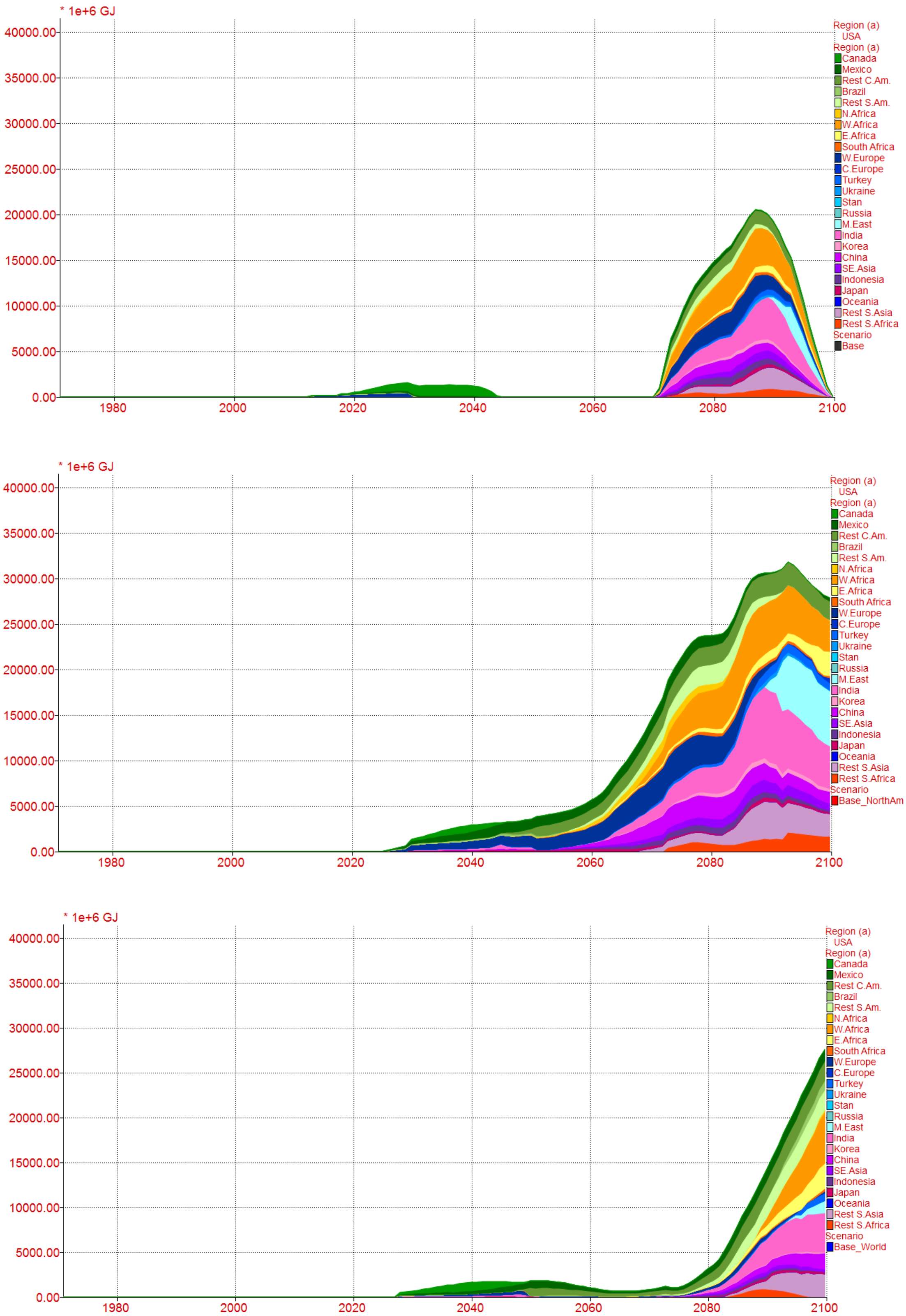
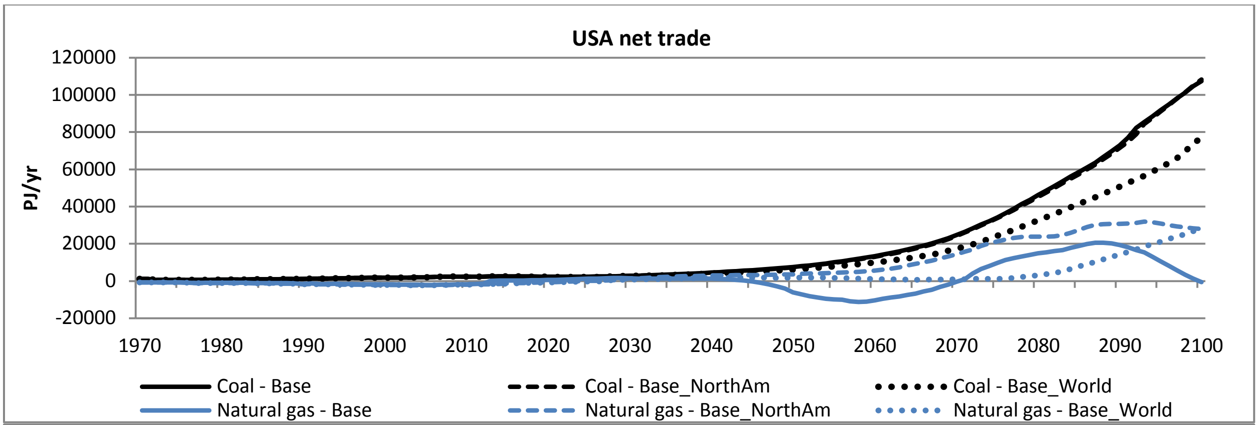
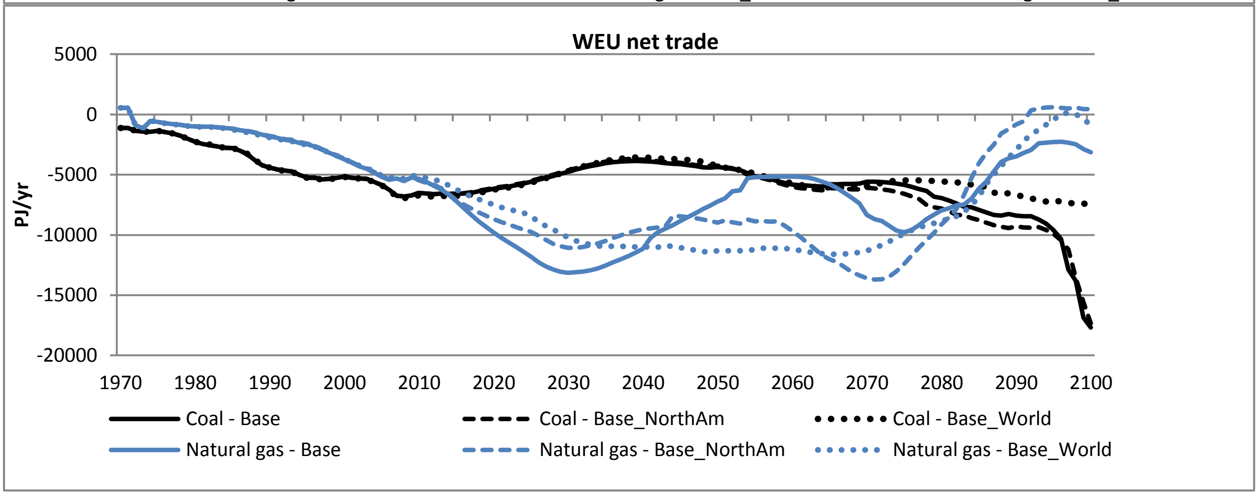


Figure 50 - Gas Net Trade from the USA to the other TIMER regions for several scenarios assuming no additional climate policy. From top to bottom: Base, Base_NorthAm and Base_World.

6.3.1 Trade of coal and gas

In the Base_NorthAm scenario the USA exports the most energy due to its still ample supplies in the second half of the 21st century. In the Base_World scenario the rest of the world has also access to these cheap gas supplies diminishing the USA's favorable export position, although the relatively large resource base in the United States still allows for some growth in export at the end of the century. When looking at the exports of coal it is seen this is only modestly driven by current events regarding potential oversupply in the United States. In the Base_NorthAm scenario coal exports from the USA remain virtually the same, indicating that the markets are not very connected. It is only in the Base_World scenario that US coal exports start to drop, presumably due to some substitution of coal by gas leading to reduced demand.





6.4 Emissions reductions in the baseline

6.4.1 Base, Base_NorthAm, Base_World

More unconventional gas in the baseline does not seem to lead to significant emission reductions in the base case scenarios by default (see Table 19). The most extreme emissions reduction for the USA and for the World occurs in the Base_World scenario. For the United States this is a reduction of 2.6% and for the whole world a reduction of 2.9% in total CO2 emissions over the period 2010-2100 in this scenario. The emission reductions in Base_NorthAM follow, as expected, the pattern of emission reductions in Base_World closely. Figure 51 shows the yearly CO_2-emissions over time for the world and the United States.

Table 19 - Total cumulative CO2 emissions in Gt CO_2 over the period 2010-2100 for the base scenarios.

Region	Base	Base_NorthAm	Base_World
USA	499.0	486.9	485.2
World	5125.9	5109.8	4975.9

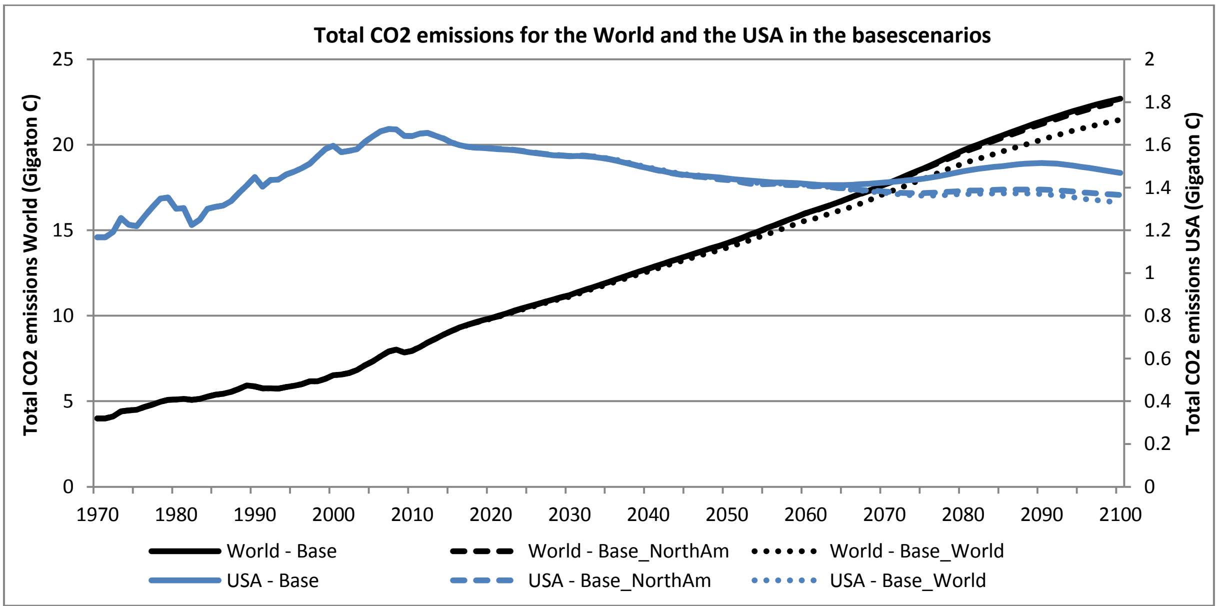


Figure 51 – Total CO2 emissions in gigaton Carbon for the United States and the whole world over the period 1971-2100 for the base scenarios.

For the United States most savings occur in the electricity sector where natural gas substitutes for coal. In the transport sector natural gas starts to substitute for modern biofuels and oil. Also hydrogen, into which natural gas can be converted, increases heavily. At first, primarily hydrogen use in the transport sector grows quickly, explaining the lower natural gas use after which also natural gas use itself grows.

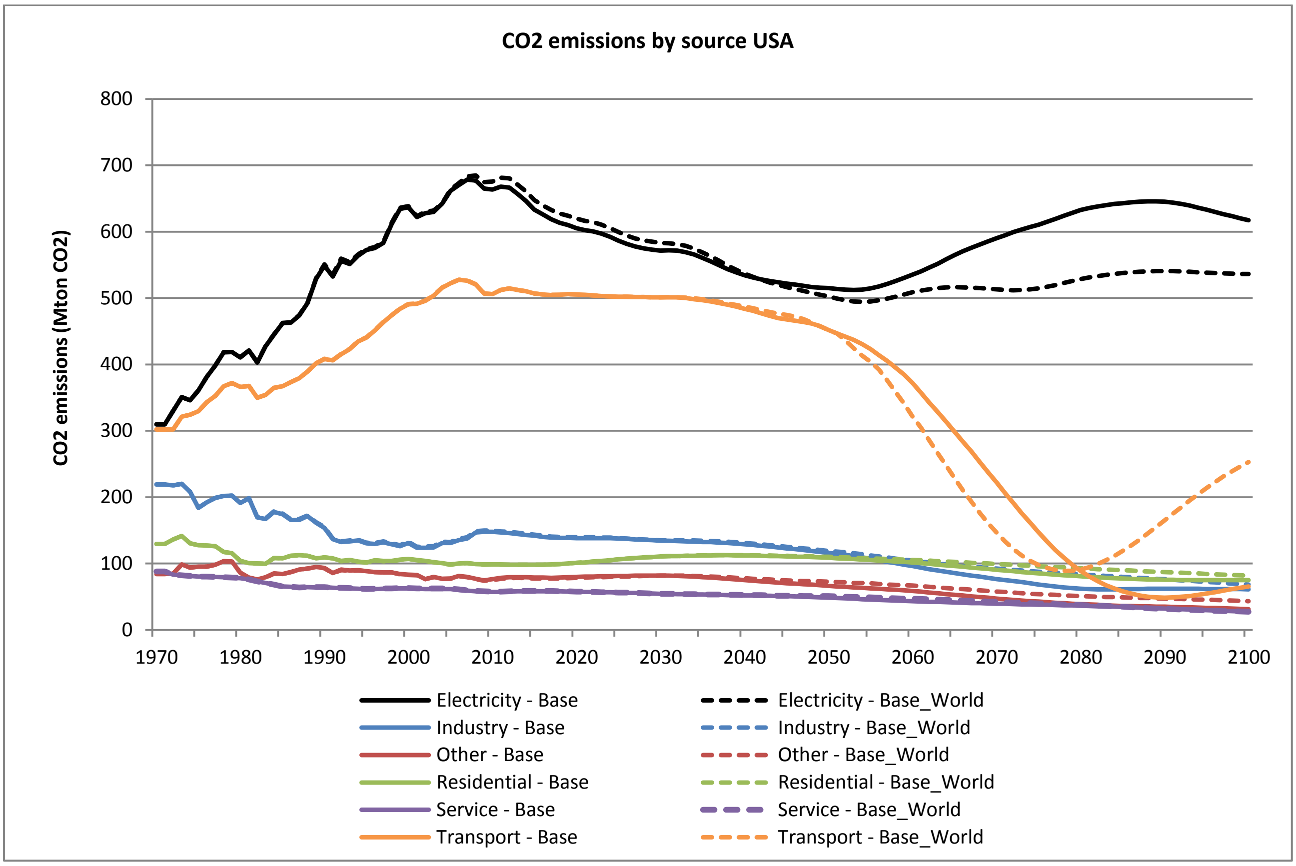


Figure 52 - CO2 emissions by source in the USA

6.4.2 450, 450_NorthAm and 450_World

In a world with a 450 ppm climate target, CCS will be applied to avoid the carbon tax placed on fossil fuels. The increased availability of natural gas leads to a reduction of the amount of carbon captured due to the lower emissions associated with natural gas use compared to other fossil energy carriers. Apart from that, CCS can be used in combination with biofuels to create negative emissions. In the 450_NorthAm and the 450_World scenarios, modern biofuel use in combination with CCS grows, leading to a respective 10.0% and 11.0% reduction in global emissions (see Table 20). For the USA the emission reductions are larger, respectively 18.3% and 19.9% emission reductions. In the 450_NorthAm scenario the amount of carbon captured is comparable to the reference scenario (see Figure 54 - Global carbon capture by source fuel in 450, 450_NorthAm and 450_World. The amount of carbon captured with modern biofuels as source is ,however, larger still. In the 450_World scenario the amount of carbon captured is lower. Coal use is also much lower compared to the 450_NorthAm scenario. In the 450_NorthAm scenario the emission reductions are mostly achieved by realizing more negative emissions with carbon capture and storage in combination with modern biofuels. In the 450_World scenario coal production is even more substituted by gas, which should lead to much lower emissions compared to the 450_NorthAm scenario. However, due to less carbon captured in the 450_world scenario (3.8%) the effect is limited. Interestingly, for the United States the amount of carbon captured increases with 2.5% and 2.3% for respectively the 450_NorthAm and 450_World scenario. Modern biofuels are the main source for this growth. By combining modern biofuels and CCS, larger negative emissions are achieved. Total emission reductions for the United States over this period are 18.4% for the 450_NorthAm scenario and 19.6% for the 450_World scenario.

Table 20 - Total cumulative CO2 emissions in Gt CO_2 over the period 2010-2100 for the 450 scenarios

Region	450	450_NorthAm	450_World
World	439.6431313	395.2636605	391.4803622
USA	121.130079	98.94138859	97.04973942

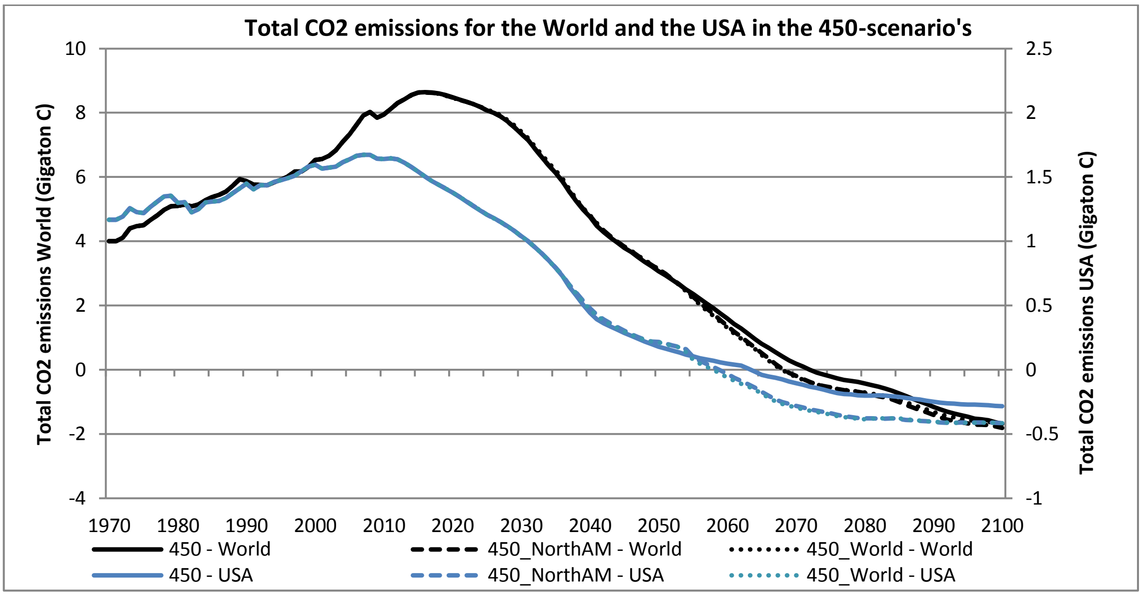


Figure 53 - Total CO2 emissions in gigaton carbon for the United States and the whole world over the period 1971-2100 for the 450 scenarios

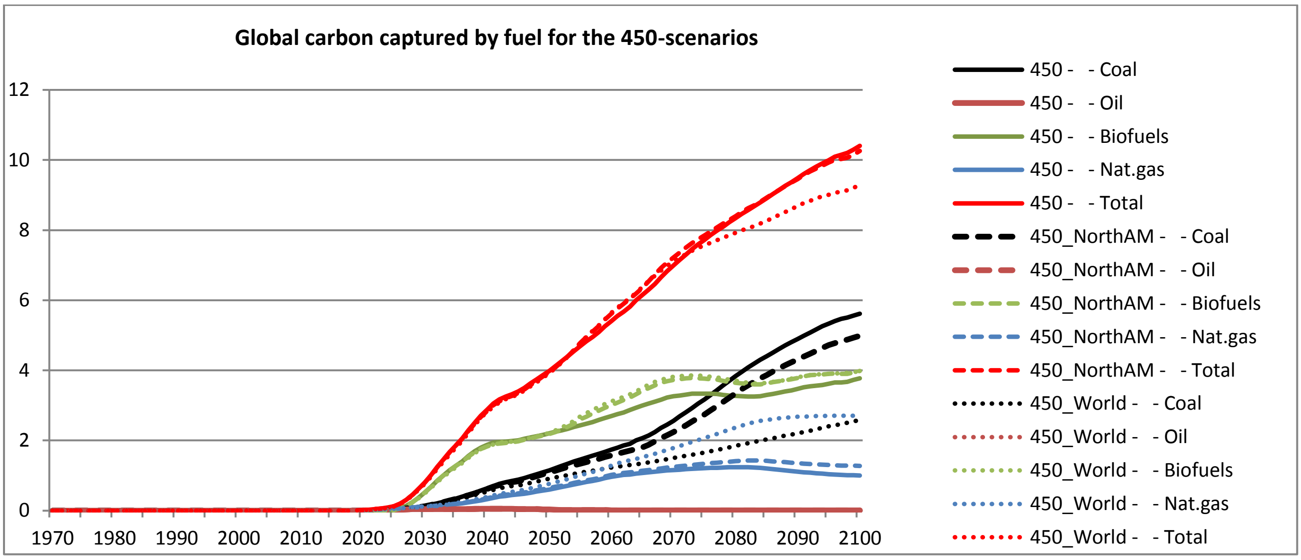


Figure 54 - Global carbon capture by source fuel in 450, 450_NorthAm and 450_World.

6.5 Methane emissions

Natural gas accounts for 46% of the energy use related methane emissions in TIMER. Losses in the upstream energy sector (venting and leakage) account for 97% of the methane emissions associated with natural gas use in TIMER over the simulation period. Although the methane emissions of gas are noticeably higher in the scenarios with Howarth et al. (2011) estimates, the methane emission factors for surface-mined coal are often a magnitude higher than the estimated methane emission factors for gas. Substituting coal by using gas thus partly mitigates the increased methane emissions due to increased natural gas emission factor. This actually realizes a reduction in TIMER when it comes to methane emissions from the energy system. In a world without climate policy and worldwide available unconventional gas supplies, it shown that using Howarth et al. assumptions on leakage rates in unconventional gasproduction adds an additional 4.8 Gtonnes of methane emitted to the atmosphere over the period 1971-2100. When a 450 ppm CO2 target is applied this is reduced to an additional 2.78 Gton of methane (see Figure 55**Error! Reference source not found.**). Figure 56 gives an overview of when these emissions occur over time. Figure 57 shows how this affects natural gas production in a carbon constrained world. Higher leakage rate seem to lead to slightly lower gas production in the 450_World and 450_NorthAm scenario with less unconventional gas production and slightly more conventional gas production.

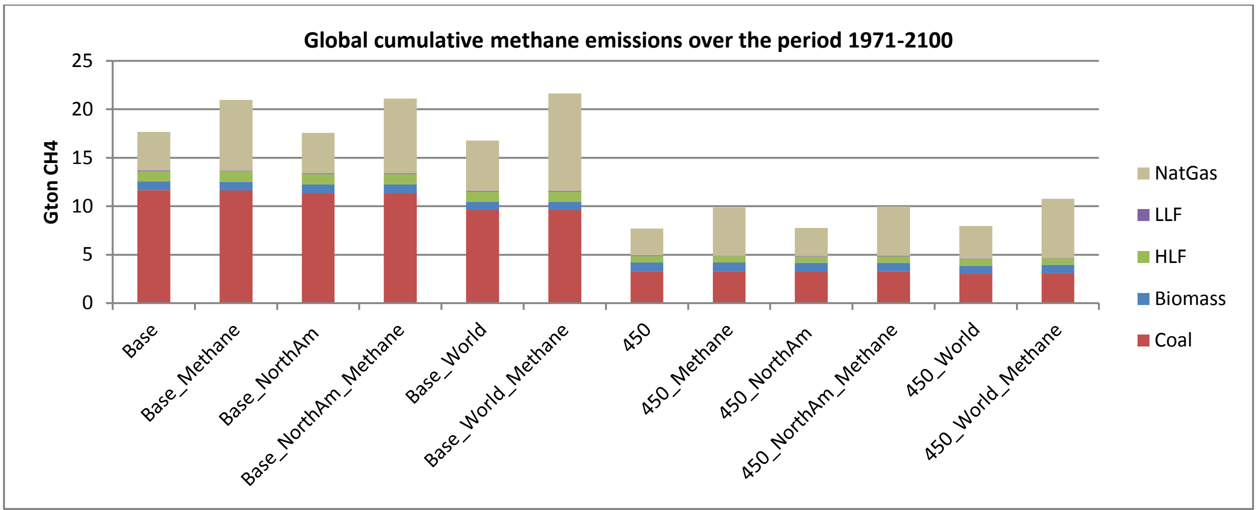


Figure 55 - Cumulative methane emissions per energy carrier over all sectors over the period 1971-2100. (LLF= Light Liquid Fuels, HLF = Heavy Liquid Fuels)

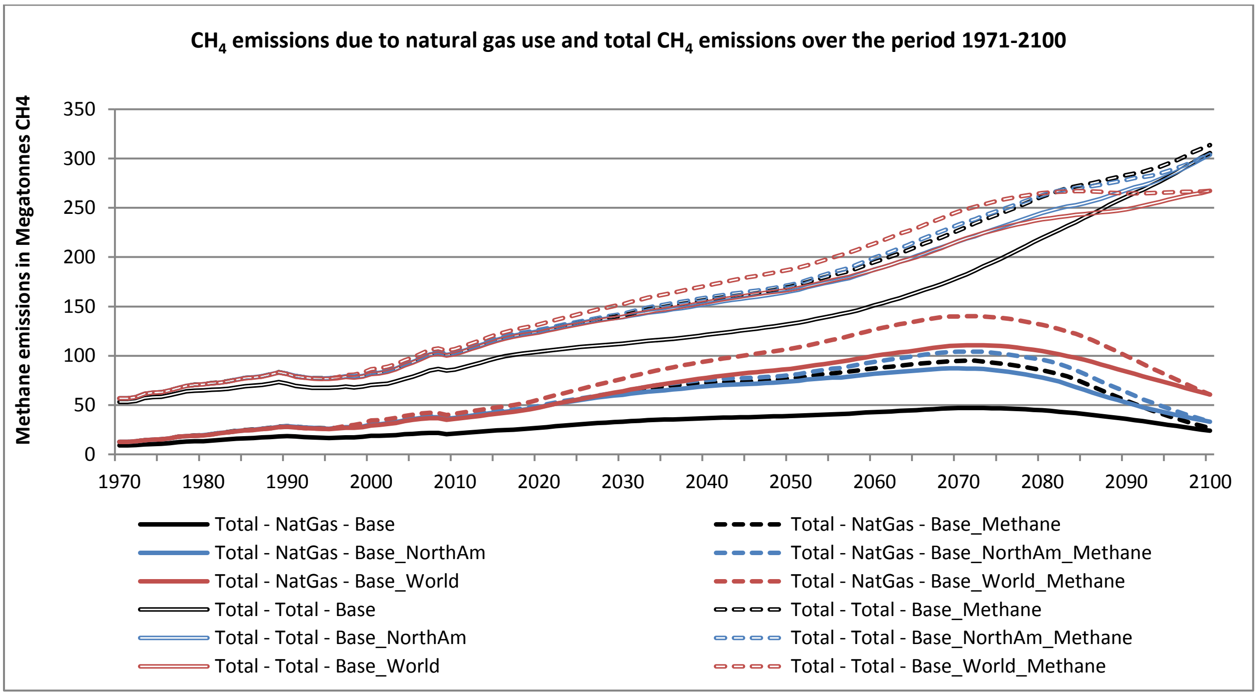


Figure 56 - Methane emissions in all sectors due to natural gas use and total methane emissions in all sectors due to energy use. (Total – NatGas = Methane emissions due to the production and use of natural gas over all sectors, Total – Total = Methane emissions due to the production and use of all energy carriers over all sectors).

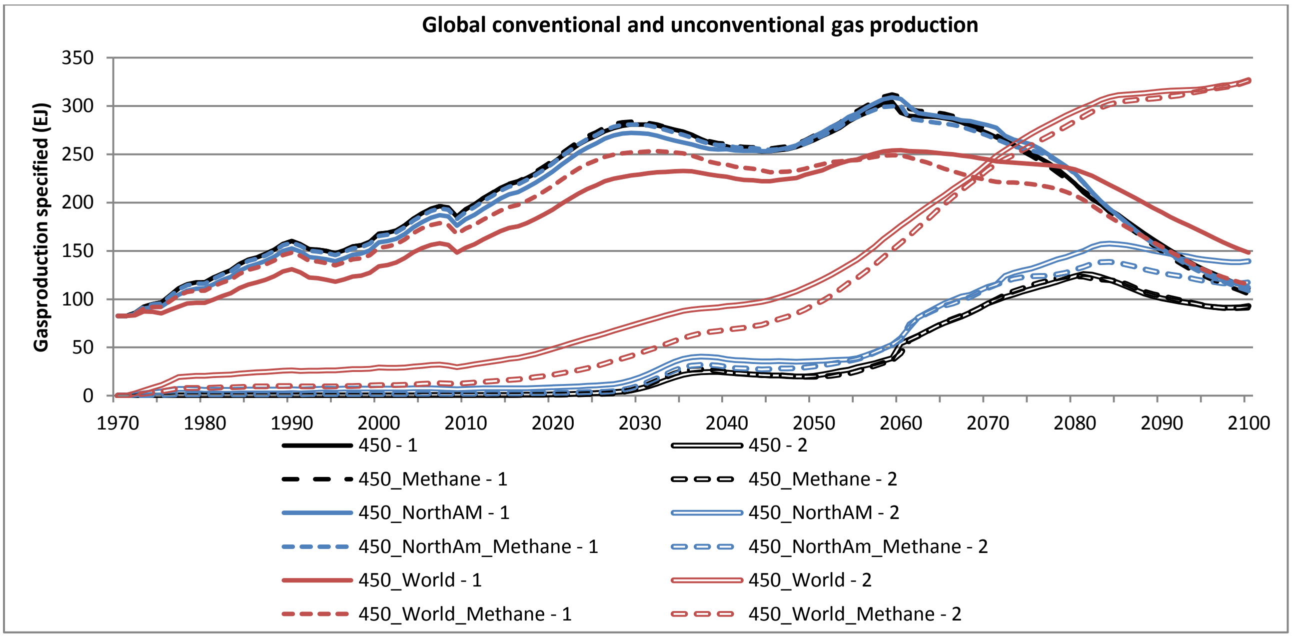


Figure 57 - Global conventional and unconventional gas production in a carbon constrained world for high methane emission and original methane emission factors. 1= conventional gas production, 2=unconventional gas production.

6.6 Altered conventional supplies

In this series of scenarios next to unconventional reserves and resources the conventional reserves and resources have been adapted to fit Rogner curves.

6.6.1 Natural gas production

6.6.1.1 Base, Base_North_Am, Base_World, Base_AltConv, Base_NorthAm_AltConv, Base_World_AltConv

Total natural gas production is slightly higher in the scenarios where the conventional supplies are altered. Although the resources are less, the lower prices seem to increase the global production of gas (see Figure 58). The pattern of production does not differ much from the scenarios with the original TIMER conventional gas supplies however on a regional level differences are more clear. Especially for the USA the original supplies in TIMER seem to be overstated. In the altered conventional scenarios gas production drops severely after 2030 in the base_Altconv scenario and does not achieve the peak in last part of the 21st century reached in the base scenario (see Figure 59).

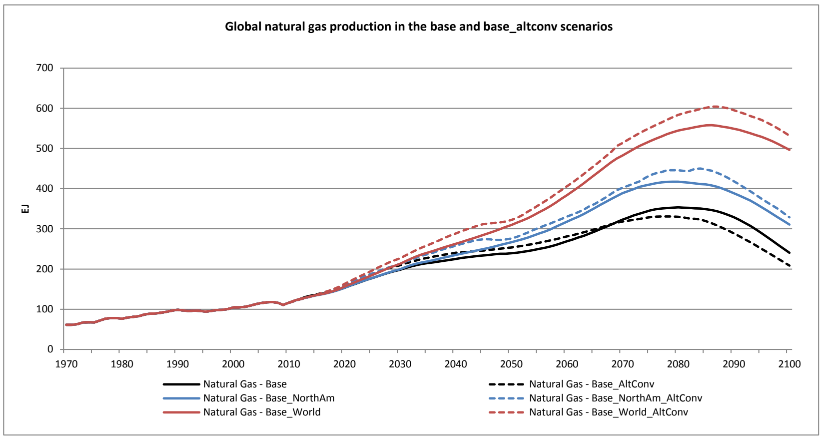


Figure 58 - Global natural gas production in scenarios where conventional and unconventional supplies have been altered compared to scenarios where only unconventional supplies are altered in a world without climate policy.

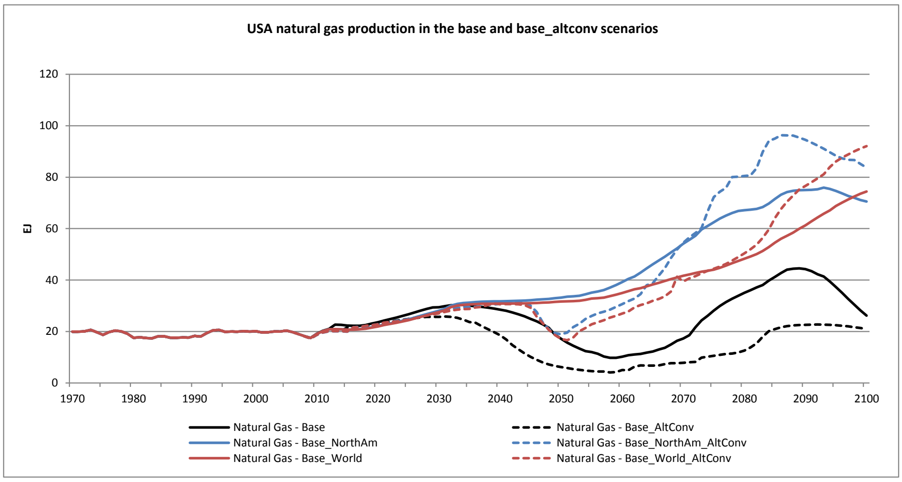


Figure 59 - Regional natural gas production in scenarios where conventional supplies have been altered compared to scenarios where only unconventional supplies are altered in a world without climate policy.

6.6.1.2 450, 450_North_Am, 450_World, 450_AltConv, 450_NorthAm_AltConv, 450_World_AltConv

The 450 scenarios show the same trends as the base scenarios with the similar gas production volumes over the simulation period in the 450 and 450_AltConv scenarios and slightly higher gas production in the scenarios with additional unconventional gas and altered conventional supplies. Regional differences are more profound, especially in Western Europe and Oceania. For Western Europe conventional supplies are much larger and cheaper in the new supply cost curve (see Appendix D.4 Regional supply cost curves where conventional and unconventional gas has been updatedleading to quick natural gas growth after the calibration period. Oceania starts exporting more natural gas after 2030 leading to a production spike. For the USA conventional supplies are smaller leading to lower production levels of gas.

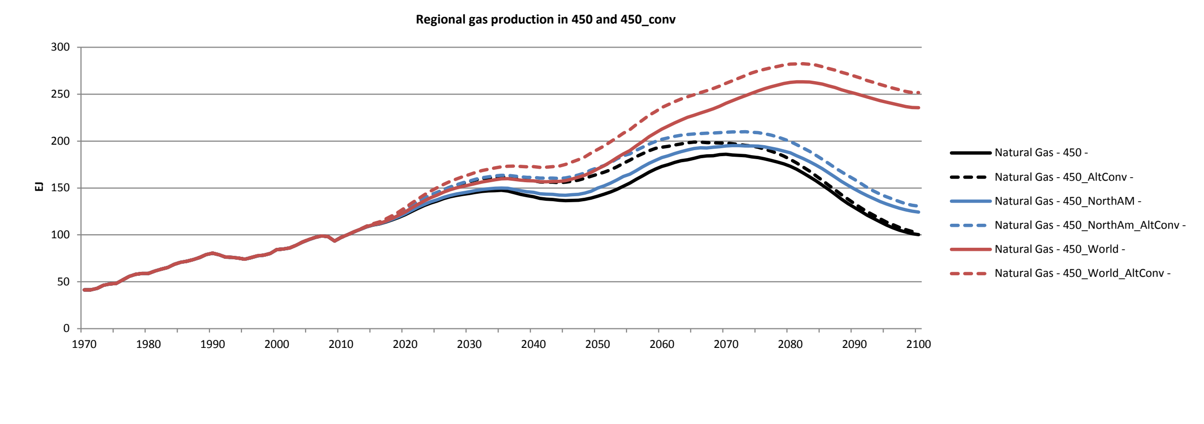


Figure 60 - Global natural gas production in scenarios where conventional and unconventional supplies have been altered compared to scenarios where only unconventional supplies are altered in a world with climate policy.

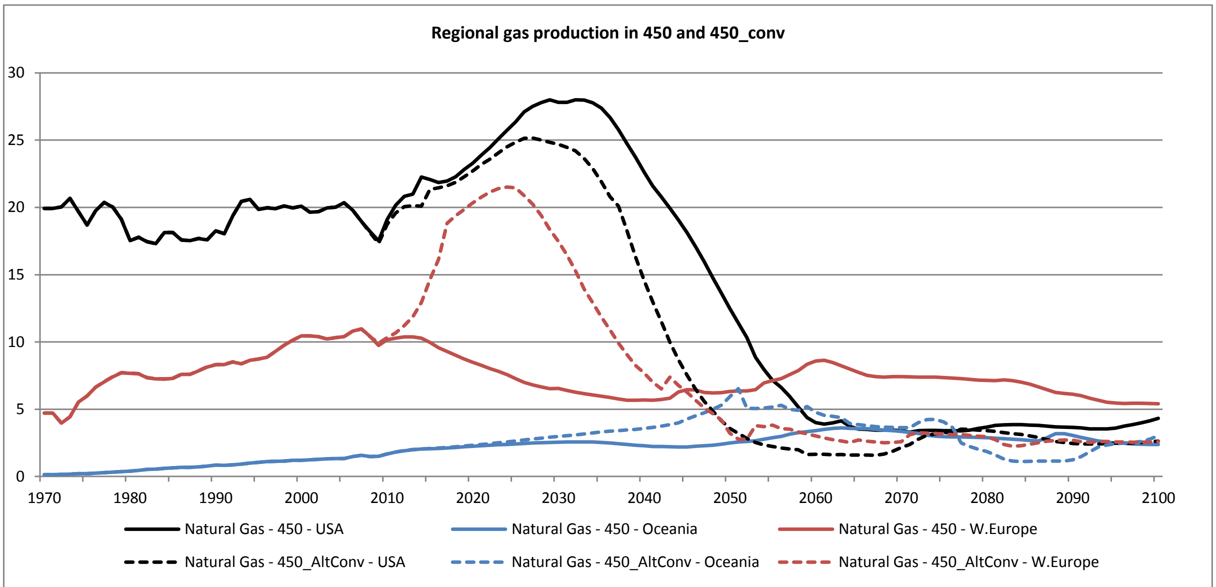


Figure 61 - Regional natural gas production in scenarios where conventional supplies have been altered compared to scenarios where only unconventional supplies are altered in a world with climate policy

6.6.2 Conventional and unconventional gas production

In the base scenarios the most notable difference is that conventional gas supplies are depleted somewhat earlier. This results in higher unconventional gas production at the end of the 21st century.

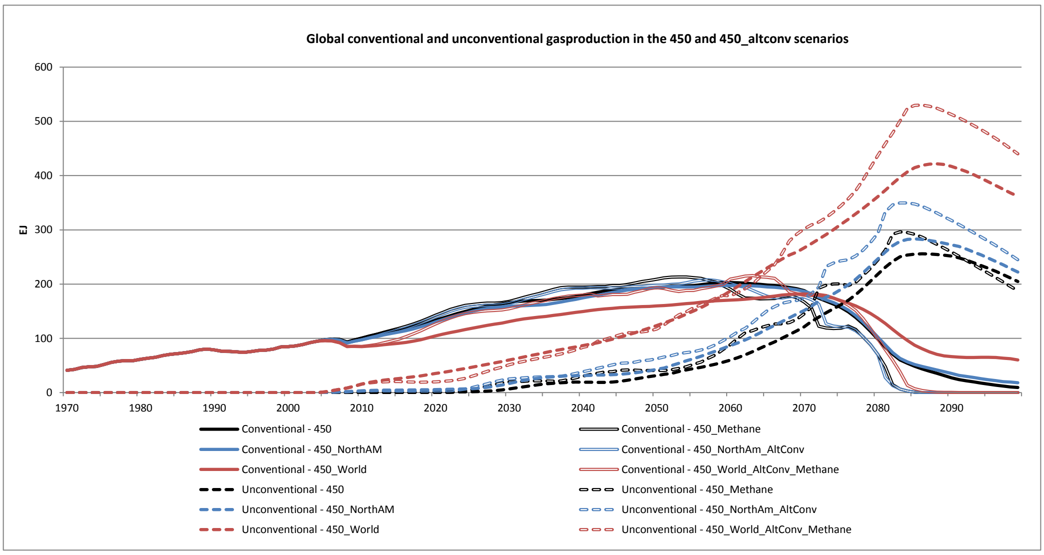


Figure 62 - Conventional and unconventional in baseline scenarios for high methane emission factors and original methane emission factors.

For the 450_Altconv scenarios global conventional and unconventional gas production remains at the same level as in the reference scenarios. If more unconventional gas becomes available gas production rises slightly leading to conventional supplies being slightly earlier depleted. The lower cost of the conventional supplies ensures a slightly higher production of conventional gas in the 450_NorthAm scenario. If the cheap unconventional gas is globally available the conventional gas production drops as unconventional gas substitutes for production. This leads to a reduction of 9% in conventional gas use over the simulation period in the 450_World_AltConv scenario.

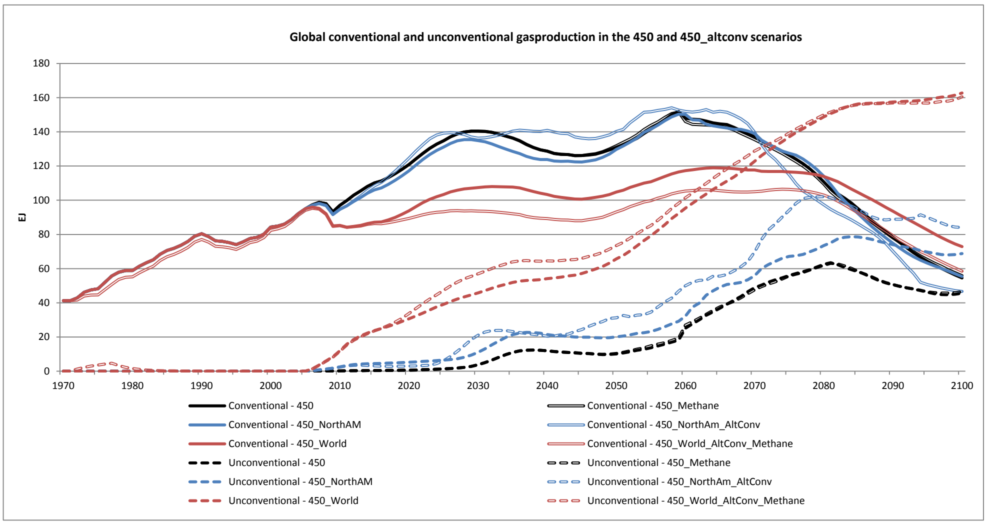


Figure 63 - Global conventional and unconventional gasproduction for a world with climate policy with various degree of conventional and unconventional gas availability.

7 Conclusion and Discussion

In this thesis an overview of technical and environmental aspects with respect to shale gas development was given. Section 7.1 will provide a short overview of the most important findings. This provides a quick summary of the issues surrounding shale gas and the current academic stance on shale gas development.

In the last part of this thesis several scenario's with respect to changes the resource base and production costs of gas have been assessed with the TIMER model. The aim was to assess how the energy mix, energy trade and the effectiveness of climate policy would be affected for different unconventional gas development scenarios. The most important findings along with their implications are discussed in section 7.2.

This is followed by a section regarding limitations of this study, 7.3, and a section regarding further research suggestions, 7.4.

7.1 Technical and environmental parameters

7.1.1 Technology

Key technologies which led to the rise of shale gas production are hydraulic fracturing and horizontal drilling. The techniques themselves are not new, innovations in seismic imaging and drilling techniques have made it possible to drill over longer horizontal lengths and have enabled more efficient fracture placement. Innovations in fracking fluid composition and the introduction of multi-stage fracturing have made it possible to more effectively fracture wells over longer lengths. Both techniques can also be used in tights sand production, coalbed methane production and conventional gas production. However, shale gas development can be distinguished by the necessity for long lateral lengths of the wellbore hole and hydraulic fracturing to achieve commercial flowrates where this is not necessarily the case in other types of gas production.

7.1.2 Reserve and resource base

Reserve and resource estimates of shale gas have improved significantly over the last decade due to increased interest. Due to large variations in productivity of shale gas wells and a lack of production data, the size of the resource base can still be considered uncertain. Current resource data does often not account for local surface conditions which could prevent unconventional gas production. The only estimate which explicitly takes these into account is for the Netherlands and arrives at an estimate of recoverable resource estimate which is two orders of magnitude smaller than the technically recoverable resource estimates made by other institutes. Current global shale gas technically recoverable resource estimates are estimated to be around 7000-8000 EJ which equals 60-70 years of current global natural gas use.

7.1.3 Water use, chemicals and leaks

Shale gas developments go paired with a higher water use in the extraction phase compared to conventional gas. For most shale gas wells in the United Stated the additional water use seems to be between 10-20 million liters. In literature water use in shale gas is often compared with conventional gas on a lifecycle basis on the premise of gas being used for electricity production. In this situation the additional water use for hydraulic fracturing is small compared to water use in cooling towers ata power plant. It should be kept in mind that the nature of the water use differs over the lifecycle stages, for example water used in cooling towers is not contaminated with chemicals. Fracking also requires a lot of water in a short period of time which can stress local water supplies. Recycling of frackwater has increased over the last years, which can reduce the amount of water need.

A wide variety of chemicals are used in hydraulic fracturing. Chemicals serve several purposes including, but not exclusively: friction reduction, biocide, anti-corrosion agent, surface tension breaker and viscosity controllers. Some of the chemicals used in fracking operations are listed as toxic and could cause human health problems or do damage to the environment in case of exposure. However, not every used fracking fluid mix contains these chemicals. Since little is known about the concentrations of the various chemicals used it is uncertain what health risks they pose. The nature of the chemicals indicate however that they are potentially dangerous.

Shale gas development has in several instances led to the contamination of water wells and groundwater in the United States. Multiple investigations have found contaminations in private water wells and groundwater which were linked to fracking operations in the area. Contaminants included methane, propane, bromide, chloride and other constituents associated with hydraulic fracturing fluid. Contamination-routes could often not be determined with certainty. Possible contamination routes are migration through the formation, upward migration through the wellbore hole, improper wastewater treatment and spills and leaks of fluids on the surface. Upward migration through the formation seems unlikely for most shale gas operations due to large depths where most shale gas development takes place. Compromised well casing integrity seems to pose a more serious threat. The cumulative risk of spills and leaks is larger is bigger in unconventional gas development compared to conventional gas development due to the larger amounts of fluids moving from and to the site and the higher number of wells necessary.

Most wastewater from shale gas developments is injected in underground. Wastewater has also been treated in publicly owned treatment works, however these are not always suitable for removing the large amount of brines and constituents present in the water, and some states in the United States have prohibited this type of treatment and require industrial treatment of waste water. Next to that, improper practices with open pits for flowback water could lead to onsite contaminations.

7.1.4 Seismic activity

Seismic activity due to hydraulic fracturing does not seem to be greater compared to conventional gas production. Since shale gas extraction is aimed at rather impermeable rock, compaction in the underground is rare. Since the fracking procedure is short and flowback water is to some extent retrieved, risks are minimized. Larger earthquakes can arise if there are pre-stressed faults in the area which are not identified. This has happened on several occasions. A larger risk seems to be associated with the injection of waste water. As opposed opposed to fracking there is no flowback phase here which serves as pressure relief. Next tot that injected volumes and rates are often much higher. Overall earthquakes due to hydraulic fracking are not expected to surpass 3 M_L, earthquakes due to waste water injection are not expected to surpass 5 M_L.

7.1.5 Emissions

Most studies find a comparable GHG-footprint for shale gas production and conventional gas production. Only Howarth et al. (2011) estimated a GHG-footprint which is higher than coal. However in his research he deviated from the IPCC standard for the GWP of methane. Also assumptions made in this research regarding methane have been criticized by other authors. Several techniques can cost effectively play a role in mitigating additional methane emissions and are becoming mandatory in the United States. For Europe those techniques are already mandatory. With the current state of evidence it seems unlikely that shale gas emissions would be higher than coal or much higher than conventional natural gas.

7.1.6 Productivity

The long-term performance of shale gas is still unknown and it could be the case that current projected EUR's are overstated. Current EUR's are projected with decline curve analysis but at the moment there is no strict consensus on how this should be applied. Several leaked industry emails have pointed to the possibility of EUR overstatement by companies. The EUR of shale gas wells is also one of the most important factors in the financial performance of shale gas wells and uncertainty regarding the EUR therefore also reflects in concerns about the profitability of shale gas extraction. Technological improvements have however led to increases in production rates over the past years. Long-term data is still necessary to provide a conclusive answer. Compared to conventional wells in the Netherlands the per well productivity of currently producing shale gas plays is low. The amount of wells necessary is therefore much larger in comparison to conventional production. This could pose a threat to the environment and interfere with other spatial development plans.

7.2 Unconventional gas in TIMER

7.2.1 Effects on the global energy mix

The incorporation of the new unconventional gas prices and gas resources as provided by Rogner (2012) leads to more global gas production, especially in the second half of the 21st century. Conventional gas production remains dominant for most regions in the first half of the 21st century.

For the base scenarios the increases in production levels are the strongest. If unconventional gas development stays limited to North America there is an additional gas use of 6% over the period 2005-2100 in the base scenario. In the 450 scenario 5% additional gas is used. In case of global availability of cheap unconventional gas supplies, gas production there is an additional gas use of 36% in the base case and 27% in the 450 scenario.

The additional natural gas production substitutes mostly for coal in the electricity sector in both the base and the 450 scenarios. Next to that unconventional gas substitutes for renewables if no extra measures are taken. Especially the use of modern biofuels decreases in the transport and industry sector, while natural gas use in this sectors increases. In case of a carbon tax renewable production is hardly affected.

The implementation of the new supply cost curves in TIMER does not seem to replicate the fast production growth for unconventional gas seen in North America over the past years. Current production data shows that unconventional gas production already surpassed conventional gas production in 2008 whereas in TIMER this does not happen till 2050 (EIA, 2013). If the conventional gas prices and gas resources are also updated this shifts to 2045. Since unconventional production can only start at 2005 in the current model there is a slight discrepancy between historic data and the simulated data with respect to unconventional gas. When the model was allowed to produce unconventional gas resources from the start of the simulation, unconventional gas production still did not reach the production levels for unconventional gas production currently seen in North America. It could therefore be that current levels of unconventional gas production in North America are higher than they should be based on price dynamics alone. Another explanation lies in the fact that shale gas producers are now primarily looking into shale gas wells which coproduce NGL's. Since NGL prices are linked to the oil price it could still make sense to produce gas-wells even if the gas price is too low to justify it for economic reasons. Other explanations lie in incorrect assumptions on the price data of unconventional gas in the USA since data with respect to the production cost and resource estimates is subjected to a high degree of uncertainty.

7.2.2 Effects on energy trade

In both reference scenarios the United States is dependent on gas imports for a part of the second half of the 21st century. If cheap additional unconventional gas resources are made available this changes and North America becomes, together with Russia and the Middle-East, one of the largest natural gas exporters in the second half of the 21st century. The USA substitutes also for some of the market share of these natural gas exporters. Coal exports from the United States are hardly affected, the same goes for coal imports into Western Europe. Increased coal imports in Western Europe due to a current surplus in coal production capital in the United States and the resulting drop are not reflected in TIMER since in the model an efficient market is simulated.

In the Base_World and 450_World scenarios the favourable export position of the United States is diminished and exports drop significantly. In these scenario's the trade in coal also decreases as a result of a reduced global demand for coal.

7.2.3 Effects on the effectiveness of climate policy

The increased production of natural gas does not lead to large emission reductions in the baseline. If cheap unconventional gas resources are limited to North America the global emission reductions are marginal. For the United States itself it leads to 2.6% less CO_2 emitted over the period 2010-2100. In a scenario where the cheap unconventional gas resources are globally available the emission reductions in the United States are similar. Globally there is 2.9% less CO_2 emitted over the period 2010-2100.

In a world with a carbon tax increased availability of unconventional gas leads to substantial emission reductions. CO_2 emission reductions are much larger, 10% for the situation where cheap unconventional gas is limited to North America and 11% when those resources are globally available over the period 2010-2100. Emission reductions are achieved by preventing direct emissions due to coal substitution as well as increasing negative emissions by combining modern biofuel use with CCS. For North America the opposite happens as the increased gas use leads to more CCS, on a global scale this is offset due to reduced coal use. For North America the reduction in the amount of carbon captured is similar with 5.9% less carbon captured in the scenario where cheap unconventional gas resources are limited to this region.

7.2.4 Effects of higher methane leakage

The effects of a higher methane emission factor for unconventional gas is limited. Coal production, especially in the case of surface mining, also emits considerable amounts of methane. Substitution effects are stronger compared to the additional emissions. A higher emission factor for methane does lead to more conventional gas use over unconventional gas use.

7.2.5 Effects of altered conventional gas supplies

The effect of altered conventional supplies on the global energy mix is limited, regional effects can however be significant, Gas production becomes slightly higher due to the cheaper available resources in the first half of the century. There are less conventional resources incorporated than in the current model leading to higher unconventional production levels as conventional gas resources become depleted. Regional effects can be large which is seen in Western Europe and Oceania for which conventional gas production grows rapidly. The United States experiences smaller gas production levels in the base cases as result of the smaller conventional supplies.

7.3 Limitations

Overall this study makes no assumptions with respect to the actual potential of unconventional gas development. The amount of the unconventional gas resource base which will actually be produced will depend on more factors than the production cost and the resource base. Local circumstances will play a large role in the feasibility of development. Next to that the reserve and production cost estimates are still highly uncertain for most parts of the worlds. Most regions have little experience with unconventional production and actual production data is instrumental in giving reducing uncertainty with respect to these topics.

Another limitation in this study is that the TIMER model assumes an efficient market for most of its dynamics. Real gas markets are confronted with more uncertainty and strategic considerations of various actors involved which can lead to considerable different dynamics. The results presented in this study therefore hold no predictive value and should not be interpreted as such but rather as an indication of which dynamics could prove to be important.

The carbon tax used to simulate a 450 ppm CO_2 is calibrated for the reference scenario to reach the 450 ppm climate target at the end of the century. Since in the assessed scenarios assumptions on which the carbon tax was calibrated were changed it could be the case for the model to not reach exactly the 450 ppm CO2 concentration in the atmosphere at the end of the century.

In order to preserve regional differences in emission factors, expected additional emissions due to shale gas development were added to already present conventional gas emission factors. Factors which determine the emission factor for conventional gas are however not necessarily applicable to unconventional gas (e.g. the amount of flaring due to no access to the grid). It could therefore be that current emission factors for conventional gas development are higher than would be the case for unconventional gas. Next to that the model does not account for reduced emission completion techniques in early stadiums of the simulation.

Differences in technological learning rates are not accounted for in this study. Over the past years advancements have been made in production rates and EUR per well. It can therefore be expected that the future production cost of unconventional gas lowers at a more rapid pace than currently modelled.

Next to that shale gas production can be associated with NGL production which improves the economics of shale gas wells. In this study shale gas production is assumed to be dry which could imply the actual production costs of shale gas are lower. Due to persistent low natural gas prices current trends in North America indicate that producers are looking for shale gas wells which will coproduce natural gas these NGL’s in order to achieve better economics. This trend is not simulated in TIMER.

7.4 Further research suggestions

The TIMER model does not explicitly distinguish between conventional and unconventional gas technologies. Even though they overlap there are some distinct differences with respect to costs, spatial requirements, learning rates, water use and societal acceptance. This research has been a first investigation into unconventional gas behaviour in TIMER but has not yet captured all possible facets of the differences. Further research should try to focus on making a clearer distinction between conventional and unconventional gas in the TIMER model by incorporating more of these differences. Furthermore the role of NGL’s seem to become more important as they play a role in the competiveness of the chemical industry and as a driver for continued drilling into shale gas formations. At the moment NGL’s reserves are included in the oil reserves in TIMER and further not separately distinguished. More explicit modelling of NGL’s could be useful for further analysis of unconventional gas drivers.

Acknowledgements

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APPENDIX A. Conversion factors

Kilojoule	= 10^3 joule
Megajoule	= 10^6 joule
Gigajoule	= 10^9 joule
Terajoule	=10^{12} joule
Petajoule	=10^{15} joule
Exajoule	=10^{18} joule

1 cubic feet of natural gas = 1.087 MJ

1 MCF (thousand cubic feet) = 1.087 GJ

1 MMCF (million cubic feet) = 1.087 TJ

1 BCF (billion cubic feet) = 1.087 PJ

1 TCF (trillion cubic feet) = 1.087 EJ

1 cubic feet = 0.028 m^3

1 m^3 of natural gas = 38.387 MJ

1 million m^3 of natural gas = 38.387 TJ

1 bcm (billion cubic metres) = 38.387 PJ

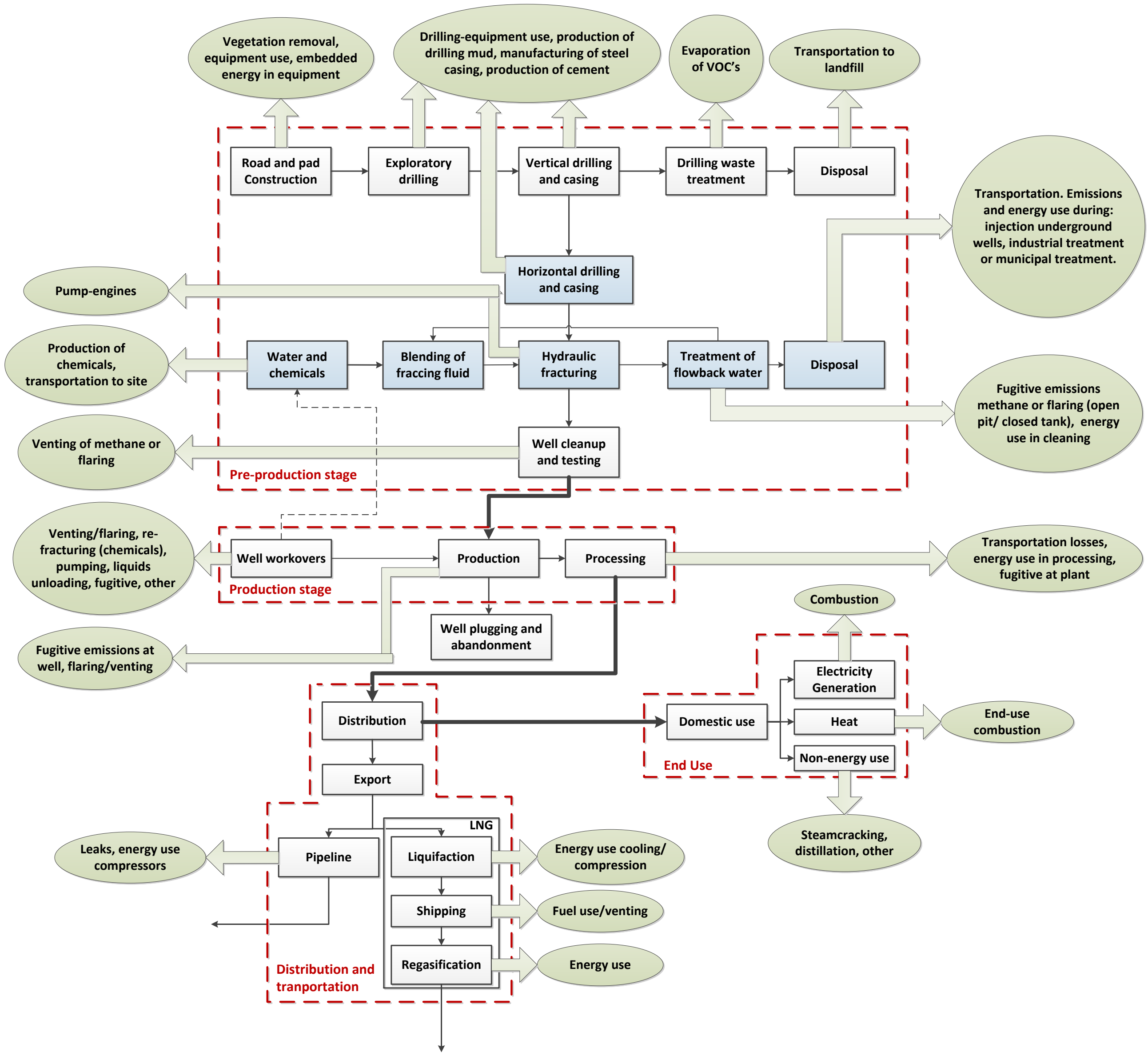
1 BOE (barrel of oil-equivalent) = 6.1508 GJ

1 TOE (tonnes of oil-equivalent) = 41.86 GJ

1 MMBTU (million British Thermal Units)= 1.055056 GJ

Appendix B. Emission sources

Procesdiagram of natural gas from exploration to end-use. Blue-coloured boxes are typical for shale gas, the rest of the overview is also applicable to conventional gas. Proces-aggregations are shown with dashed lining. Dashed arrows represent optional routes. Possible direct or indirect emission sources are depicted with green coloured arrows. Differences in the specific production process can lead to differences in emission sources. (Overview emission sources from: Weber & Clavin, 2012; AEA, 2012. Diagram pre-production and production based upon Louwen, 2009)



APPENDIX C. TIMER regions

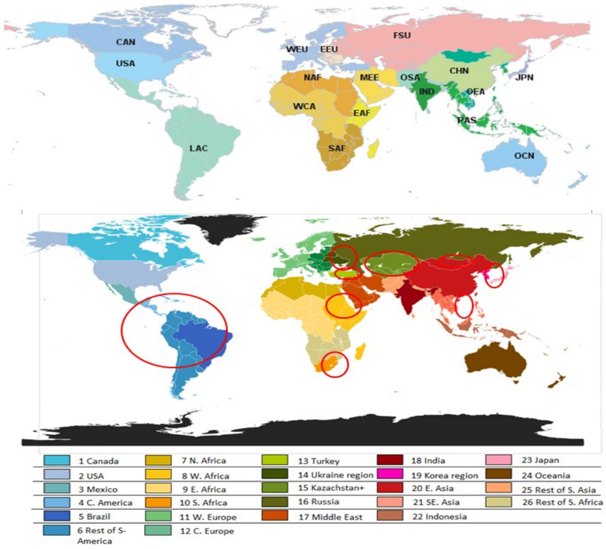


Figure 64 - Up is a map of the regions used in the GEA and down is a map of the regions in the TIMER model. Differences are marked by red circles.

Region definitions Rogner

CAN = Canada
CHN = China (incl. Hong Kong and Macao)
EAF = Eastern Africa (Burundi, Eritrea, Ethiopia, Kenya, Madagascar, Mauritius, Seychelles, Somalia, Uganda)
EEU = Central and Eastern Europe (Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Estonia, The former Yugoslav Rep. of Macedonia, Hungary, Latvia, Lithuania, Montenegro, Poland, Romania, Serbia, Slovak Republic, Slovenia)
FSU = Newly independent states of the former Soviet Union (Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine, Uzbekistan)
IND = India
JPN = Japan
LAC = Latin America and the Caribbean (Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Mexico, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Santa Lucia, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Uruguay, Venezuela)
MEE = Middle East (Bahrain, Iraq, Iran (Islamic Republic), Israel, Jordan, Kuwait, Lebanon, Occupied Palastine Territory, Oman, Qatar, Saudi Arabia, Syria (Arab Republic), United Arab Emirates, Western Sahara, Yemen)
NAF = North Africa (Algeria, Egypt (Arab Republic), Libya/SPLAJ, Morocco, Sudan, Tunisia)
OCN = Oceania (Australia, New Zealand)
OEA = Other East Asia (Cambodia, Korea (DPR), Laos (PDR), Mongolia, Viet Nam)
OSA = Other South Asia (Afghanistan, Bangladesh, Bhutan, Maldives, Nepal, Pakistan, Sri Lanka)
PAS = Other Pacific Asia (American Samoa, Brunei Darussalam, Fiji, French Polynesia, Gilbert-Kiribati, Indonesia, Malaysia, Marshall Islands, Micronesia, Myanmar, Nauru, New Caledonia, Palau, Papua, New Guinea, Philippines, Republic of Korea, Singapore, Solomon Islands, Taiwan (China), Thailand, Timor-Leste, Tonga, Tuvalu, Vanuatu, Samoa)
SAF = Southern Africa (Angola, Botswana, Burundi, Malawi, Mozambique, Namibia, Reunion, Rwanda, Saint Helena, South Africa, Swaziland, Tanzania, Zambia, Zimbabwe)

USA = Unites States (Guam, Puerto Rico, United States of America, British Virgin Islands)
WCA = Western and Central Africa (Benin, Burkina Faso, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Cote d'Ivoire, Congo (DR), Djibouti, Equatorial Guinea, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Mauritania, Niger, Nigeria, Sao Tome and Principe, Senegal, Sierra Leone, Togo)
WEU = Western Europe (Andorra, Austria, Belgium, Cyprus, Denmark, Finland, France, Germany, Greece, Greenland, Holy See, Iceland, Ireland, Italy, Liechtenstein, Luxembourg, Malta, Monaco, Netherlands, Norway, Portugal, San Marino, Spain, Sweden, Switzerland, Turkey, United Kingdom)

TIMER division to regions GEA on area			
Region ID	**Name**	**fraction of Rogner Region**	**Corresponding Rogner region**
1	Canada	1	CAN
2	USA	1	USA
3	Mexico	0.09	LAC
4	Other Central America	0.03	LAC
5	Brazil	0.42	LAC
6	Other south america	0.45	LAC
7	North africa	1	NAF
8	Western Africa	1	WCA
9	Eastern Africa[1]	0	NAF
		1	EAF
10	South Africa	0.16	SAF
11	Western Europe	0.82	WEU
12	Central Europe	1	EEU
		0.01	FSU
13	Turkey	0.18	WEU
14	Belarus/moldava/ukraine	0.04	FSU
15	Central Asia	0.18	FSU
16	Caucasus Russian Federation	0.78	FSU
17	Middle East	1	MEE
18	India	1	IND
19	Korea[2]	0	OEA
		0	PAS
20	China Monogolia[3]	1	CHN
		0	OEA
21	South -East Asia	0.44	PAS
		1	OEA
22	Indonesia/papua new guinea	0.56	PAS
23	Japan	1	JPN
24	Australia/Oceania	1	OCN
25	Other Southern Asia	1	OSA
26	Other Southern Africa	0.84	SAF
27	Greenland	-	-
28	Antartica	-	-

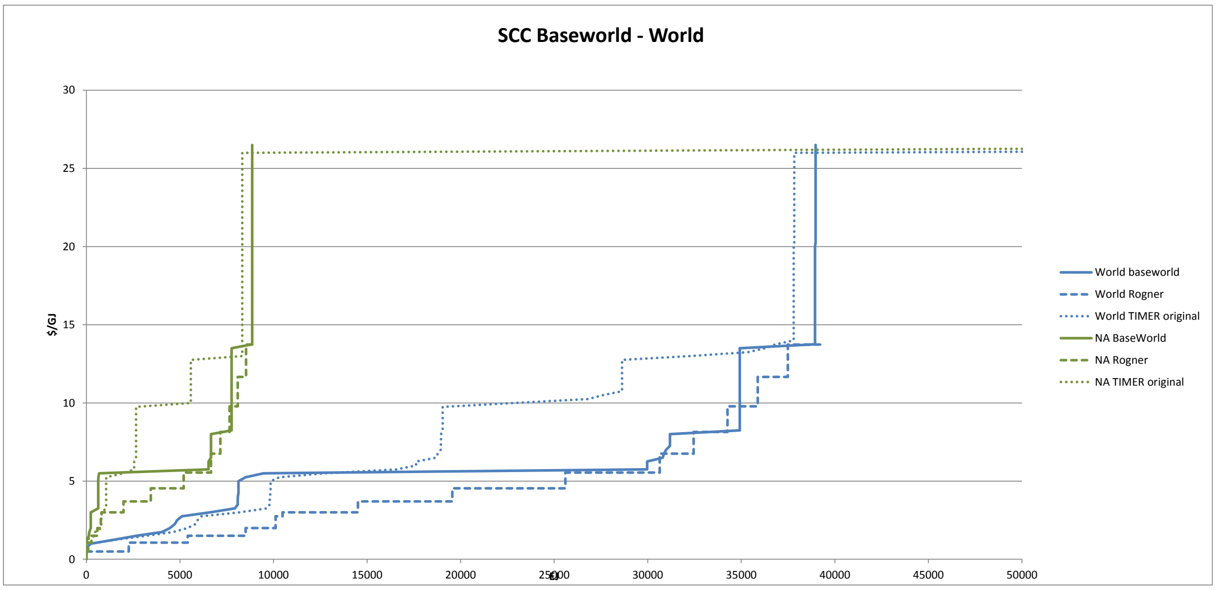
1. When comparing EAF in TIMER and in the GEA than almost a quarter of the North Africa should be included based on surface area. EIA (2013) estimates of conventional and unconventional gas reserves in Sudan show little resources compared to the large gas reserves present in the rest of North Africa and it was therefore neglected.

2. From EIA (2013) it is shown that North Korea has virtually no conventional or unconventional gas reserves and resources and it is therefore omitted.

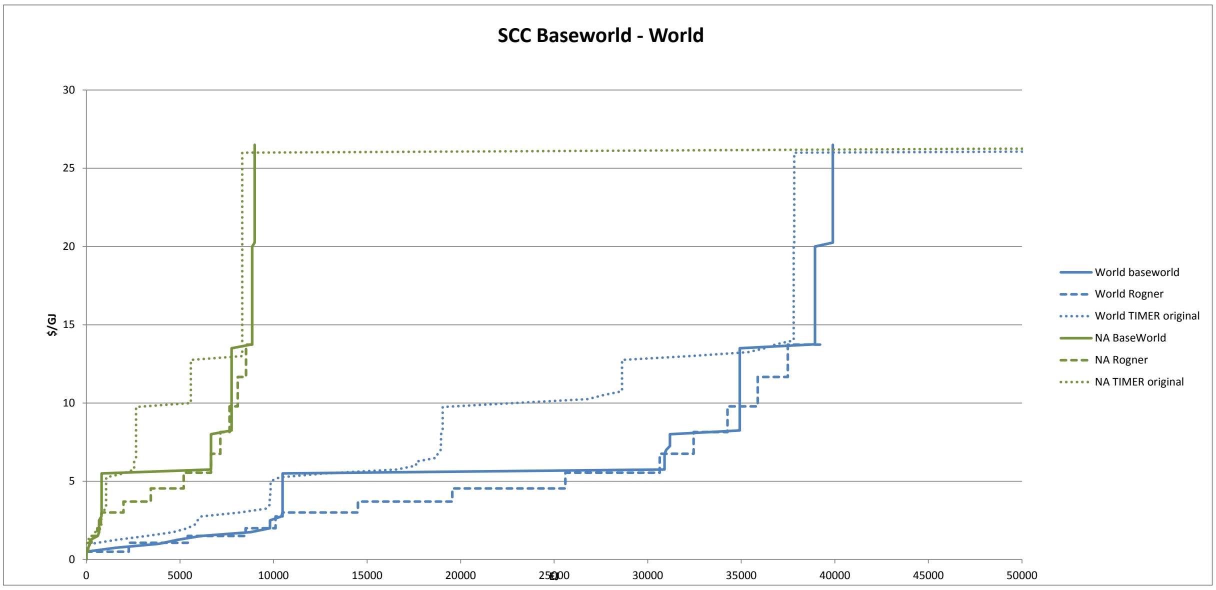
3. Although Mongolia makes up a large part of the OEA region in Rogner and based upon surface area it would acquire 0.65 of the reserves and resources (186 EJ of unconventional gas reserves and resources) an EIA (2013) surveys shows little shale gas reserves (2 EJ). Since China has extensive shale gas reserves and OEA would be dominated by Mongolia based on surface area it was omitted.

Appendix D. Supply Cost Curves

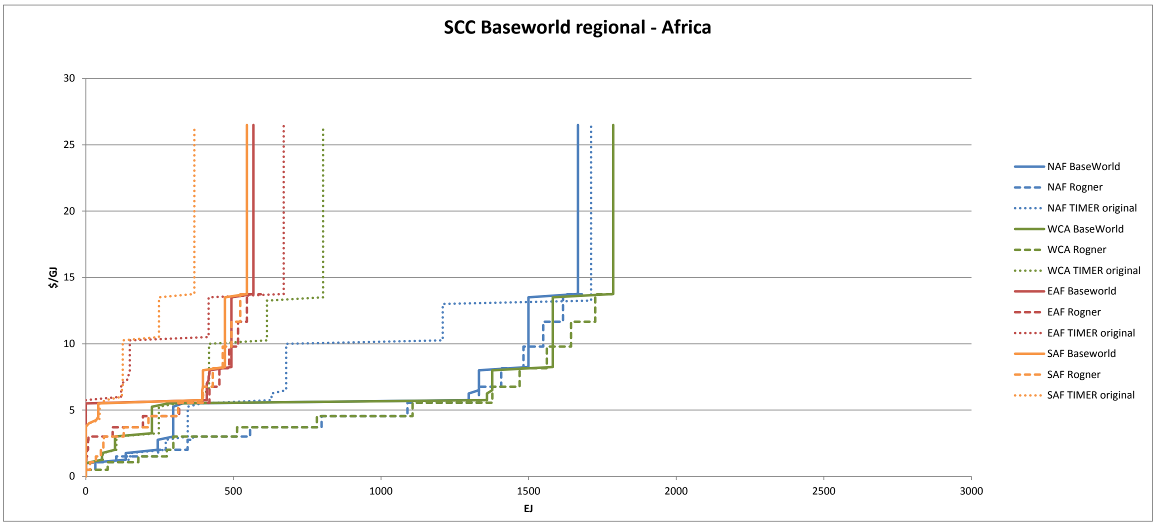
D.1 Global SCC and North American SCC with only unconventional gas updated

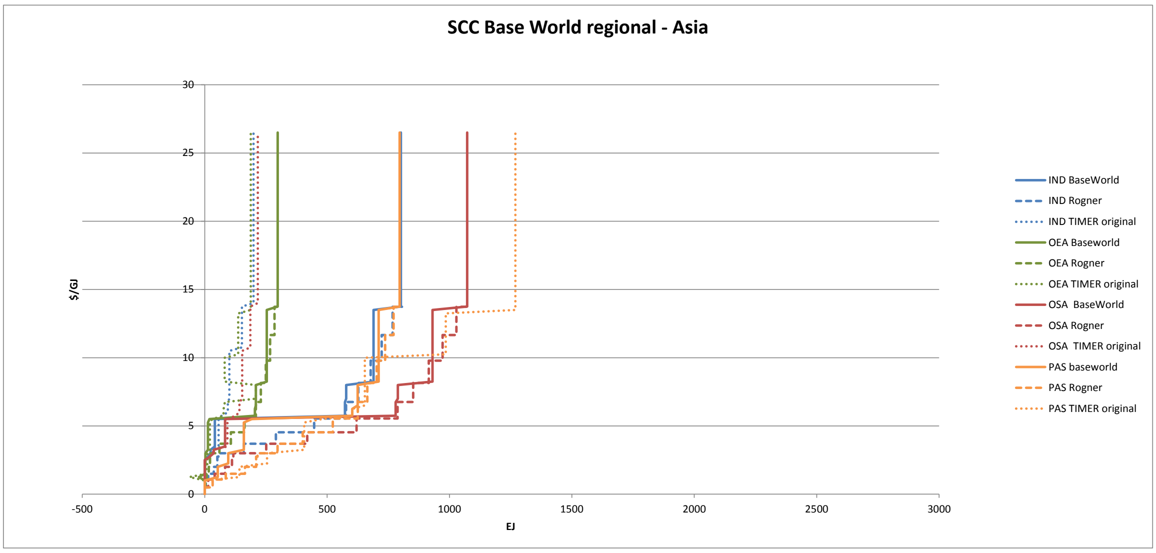


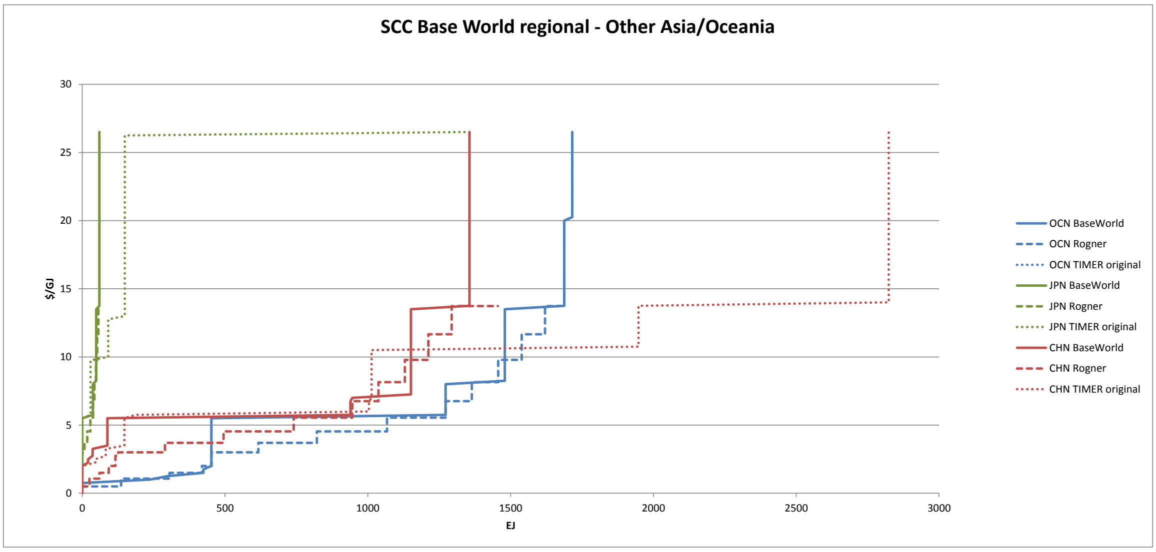
D.2 Global SCC and North American SCC with conventional and unconventional gas updated

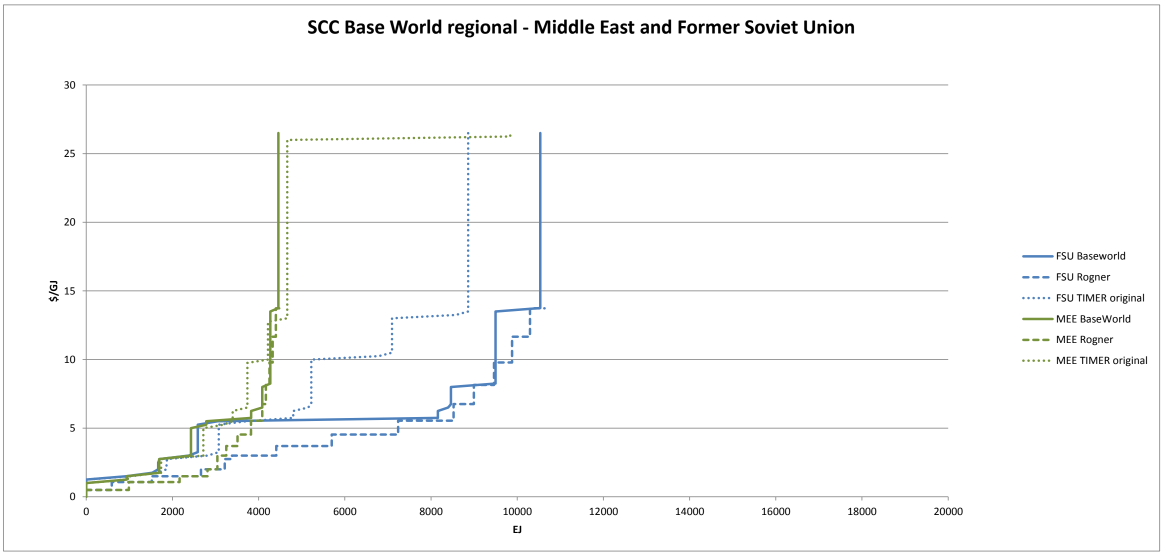


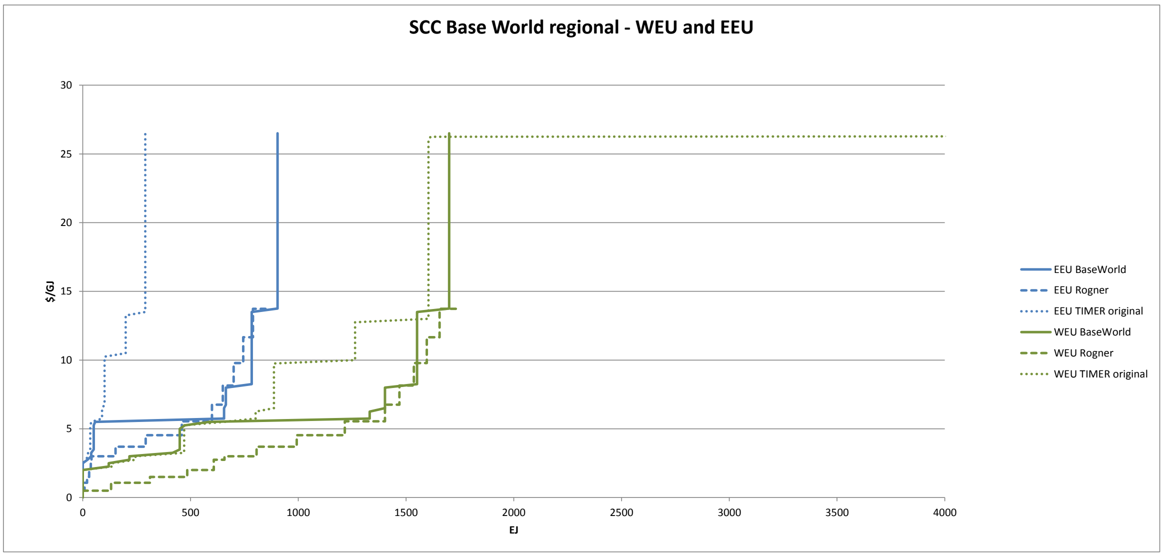
D.3 Regional supply cost curves where only unconventional gas has been updated

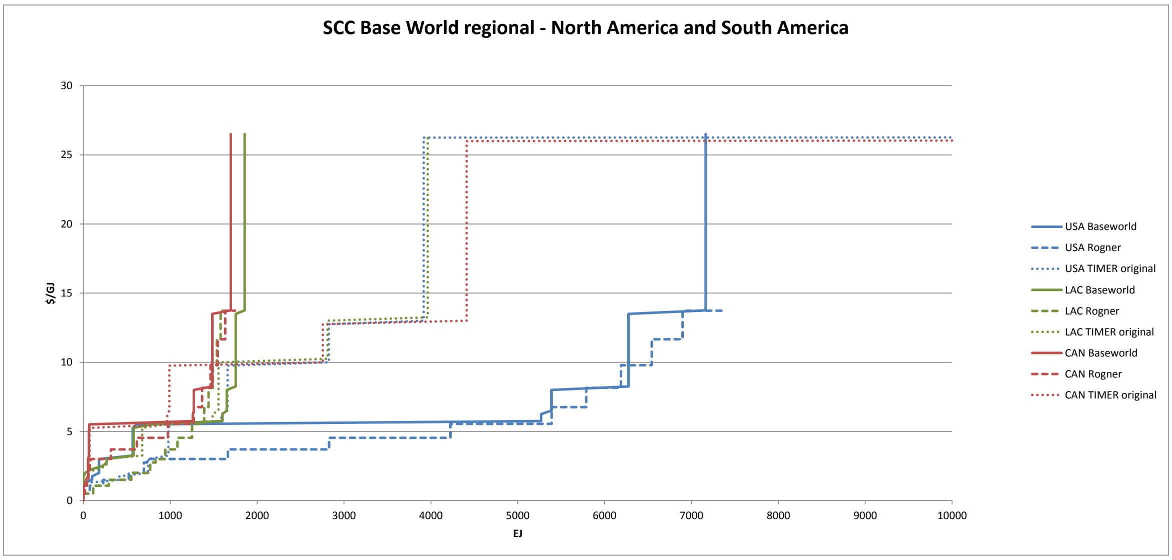




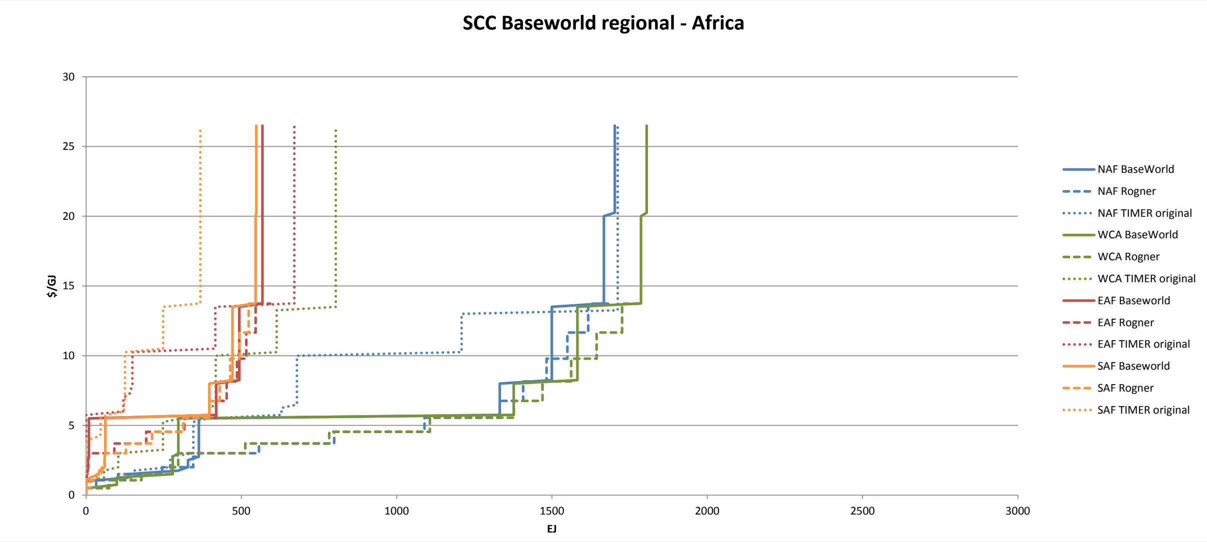


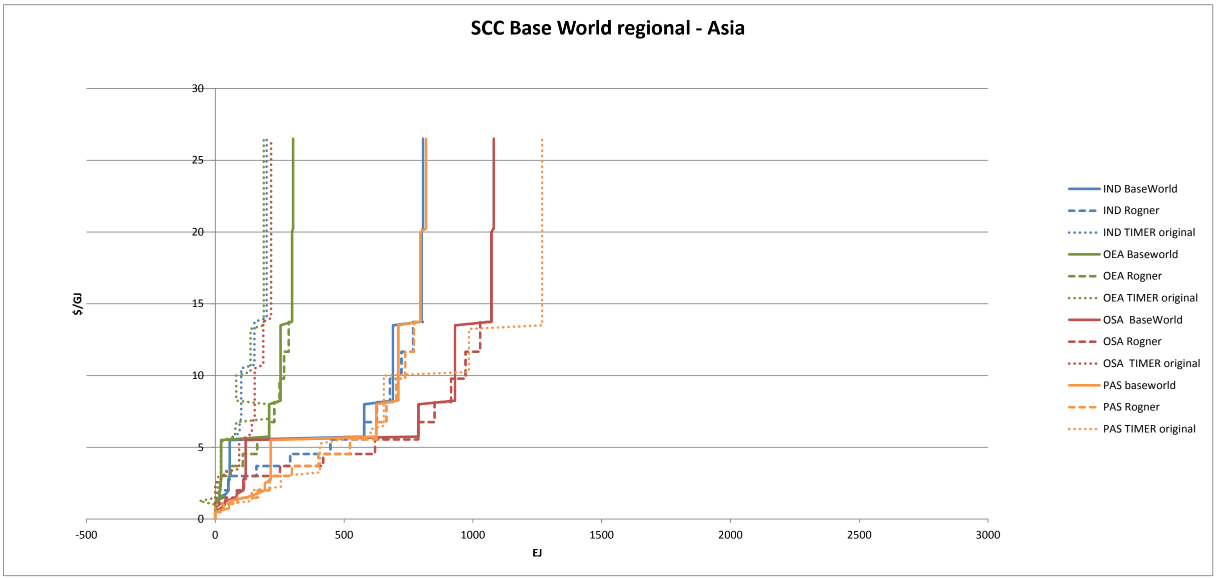

SCC Base World regional - Middle East and Former Soviet Union
$/GJ
EJ
0
5
10
15
20
25
30
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
FSU Baseworld
FSU Rogner
FSU TIMER original
MEE BaseWorld
MEE Rogner
MEE TIMER original

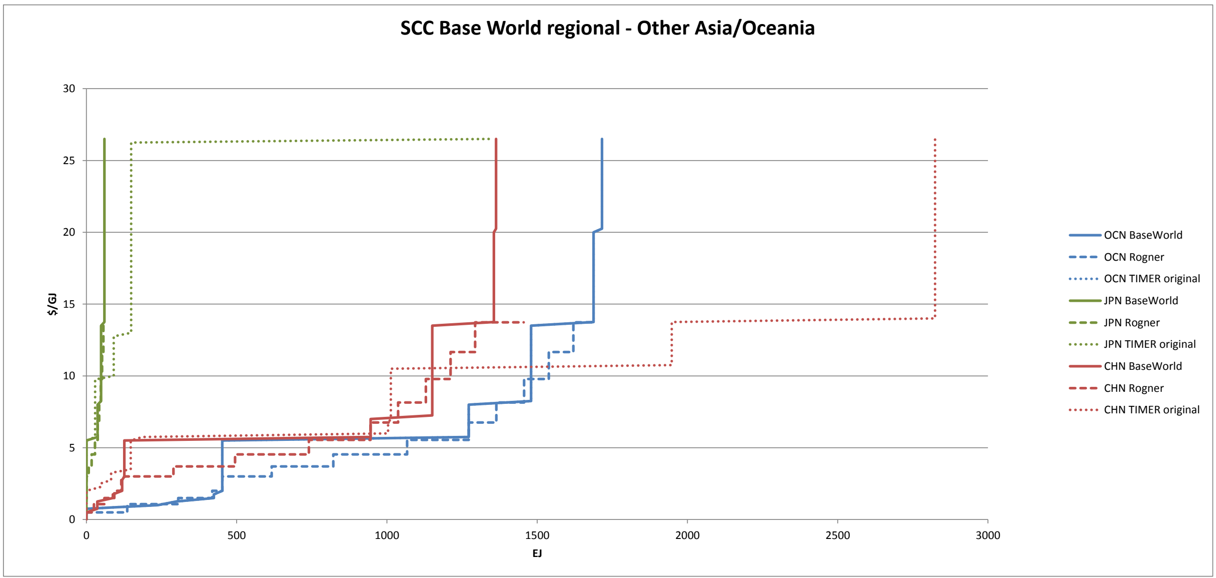

SCC Base World regional - WEU and EEU
$/GJ
EJ
0
5
10
15
20
25
30
0
500
1000
1500
2000
2500
3000
3500
4000
EEU BaseWorld
EEU Rogner
EEU TIMER original
WEU BaseWorld
WEU Rogner
WEU TIMER original

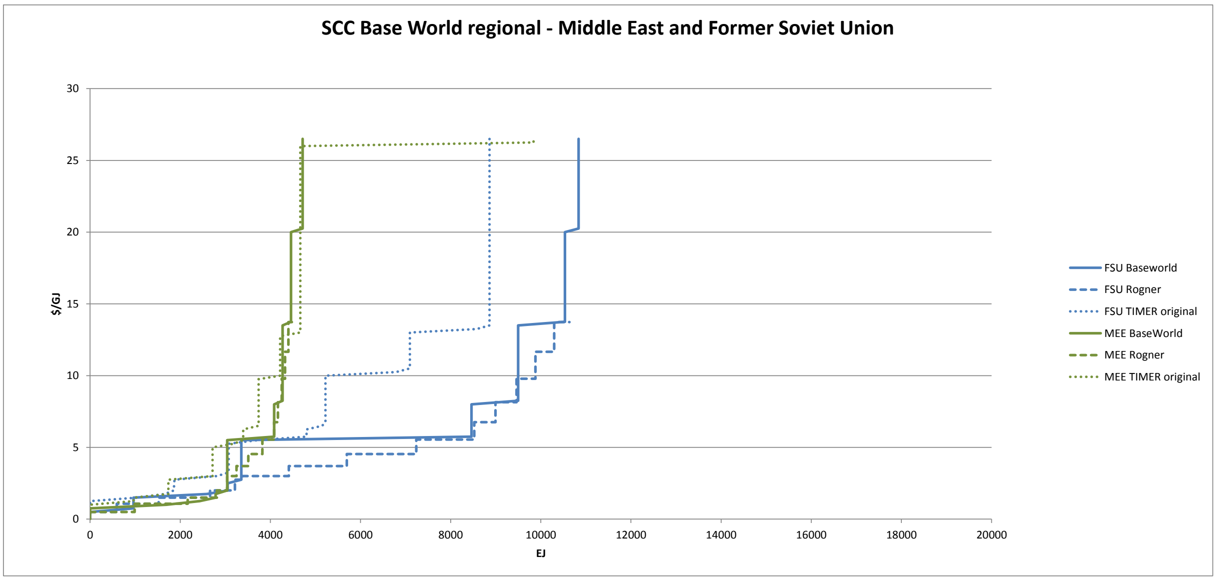

SCC Base World regional - North America and South America
$/GJ
EJ
0
5
10
15
20
25
30
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
USA Baseworld
USA Rogner
USA TIMER original
LAC Baseworld
LAC Rogner
LAC TIMER original
CAN Baseworld
CAN Rogner
CAN TIMER original

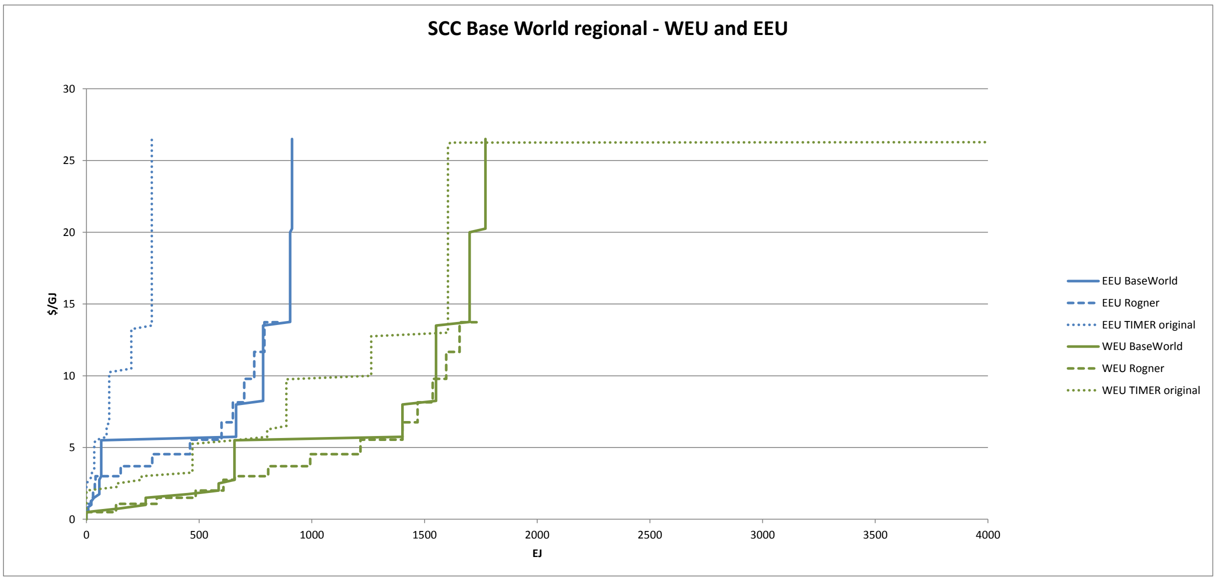
D.4 Regional supply cost curves where conventional and unconventional gas has been updated

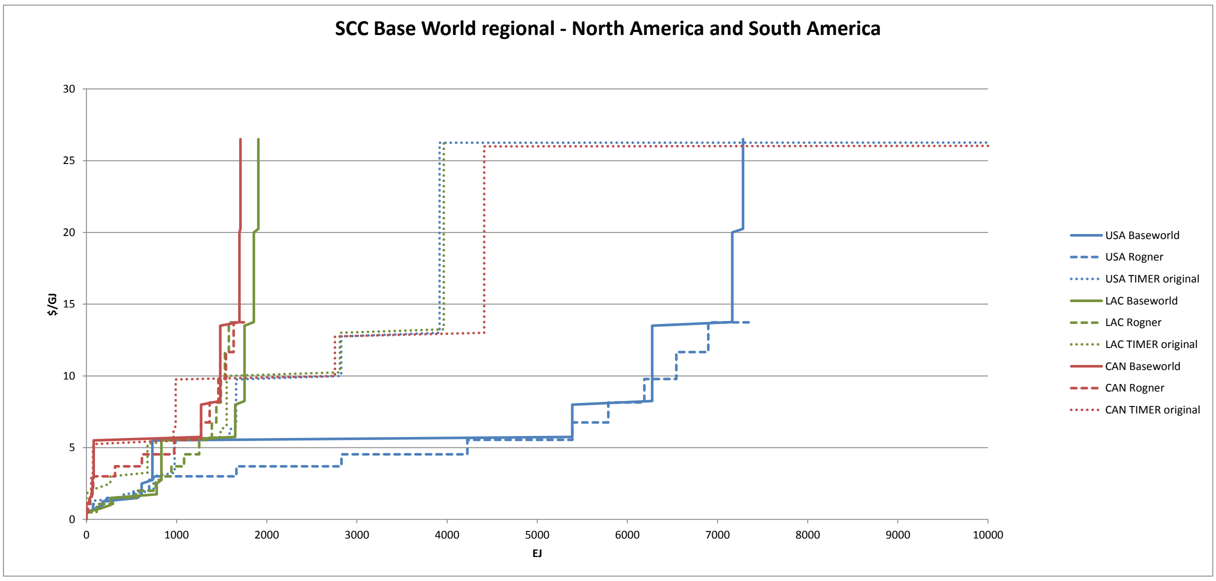







SCC Base World regional - Middle East and Former Soviet Union
$/GJ
EJ
FSU Baseworld
FSU Rogner
FSU TIMER original
MEE BaseWorld
MEE Rogner
MEE TIMER original


SCC Base World regional - WEU and EEU
$/GJ
EJ
EEU BaseWorld
EEU Rogner
EEU TIMER original
WEU BaseWorld
WEU Rogner
WEU TIMER original


SCC Base World regional - North America and South America
$/GJ
EJ
USA Baseworld
USA Rogner
USA TIMER original
LAC Baseworld
LAC Rogner
LAC TIMER original
CAN Baseworld
CAN Rogner
CAN TIMER original