Energy use in fossil resource production

On the impact of changing energy requirements of conventional and unconventional fossil resource production on global energy use and CO_2 emissions towards 2100

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Summary

The fossil resource base is vast and can supply the world's energy demand for quite some time in terms of potential amounts available in the subsurface. However, when regarding the increasing energy requirements for production of these resources, feasible amounts may very well be only a fraction of the total.

The analyzed data by the IEA indicates that gas requirements and other inputs are increasing for the production of conventional oil and gas; energy requirements for coal production are stagnating. For processing of fossil fuels, energy inputs were decreasing over time.

Case studies on unconventional oil production show that a larger amount of energy is required than for the production of conventional oil, due to the lower physical quality of the unconventional hydrocarbons. These resources can be upgraded to higher quality products that are comparable with conventional products, although at an energy cost. These upgrading and retorting processes make up the largest part of upstream energy requirement for unconventional resources, although they mainly consist of internally provided bitumen or kerogen.

Case studies on unconventional gas also show an increase in energy requirements compared to conventional gas. These changes mainly occur due to the decreasing reservoir quality and the need for unconventional methods as hydraulic fracturing.

The energy requirements for conventional and unconventional fossil resource production are incorporated in the TIMER model using an *input output energy approach*. The effects of the interdependent fossil resource production systems are analyzed by looking at the global primary energy use and CO_2 emissions towards 2100.

Baseline scenario results show that the changes made induce 13% higher annual primary energy use in 2100 than projected in the original model. Corresponding annual CO_2 emissions are projected to be 13.5% higher in 2100. These results add more pressure on efforts to sequestrate emissions.

Mitigation scenarios are simulated by imposing a carbon tax on CO_2 emissions, either on direct emissions only, or on both direct and indirect emissions that result from upstream energy losses. The relative differences in energy use and emissions between the original and enhanced model are smaller than in the baseline scenario due to substitution effects, but only when the carbon tax incorporated upstream energy losses. Imposing only a direct carbon tax leaves annual CO_2 emissions at a level of 15% higher towards 2100 compared to the original model. This indicates that it would be beneficial to incorporate fuel life cycle losses, when designing effective mitigation strategies.

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1. Introduction

Increasing CO_2 emissions are thought to be the main reason for anthropogenic climate change. Moreover, continuous energy demand growth and the uneven distribution of energy and material resources pose challenges for scarcity induced energy price increases and uncertainty about future energy security. Renewable energy is often seen as the solution for these problems, although the transition to an entirely renewable energy supply will take some time. Currently, more than 75 % of the world's energy supply consists of fossil fuels and projections for scenarios without strong climate policy show that this will slightly decrease to 70% of the worldwide energy supply by 2035 (see Figure 1.1 for an overview). The pool of fossil resources, including unconventional resources, is vast and could possibly supply energy for several decades to come [IEA, 2011; BP, 2014]. As can be seen from Figure 1.2, unconventional fossil fuels can gain significant market shares in some of the more market-driven scenarios. However, at the same time, this coincides with a degrading quality of resources leading to increased energy consumption and related emissions. Consequently, it is of importance to monitor the quality of resources and incorporate these in assessments of reserves and resources.

Figure 1.1. World primary energy demand by fuel in the New Policies Scenario [IEA, 2011].

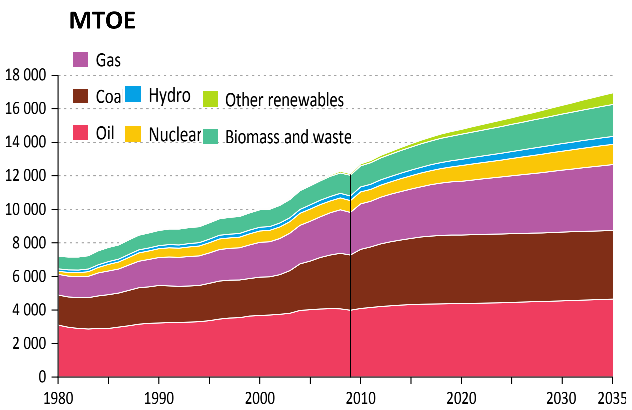
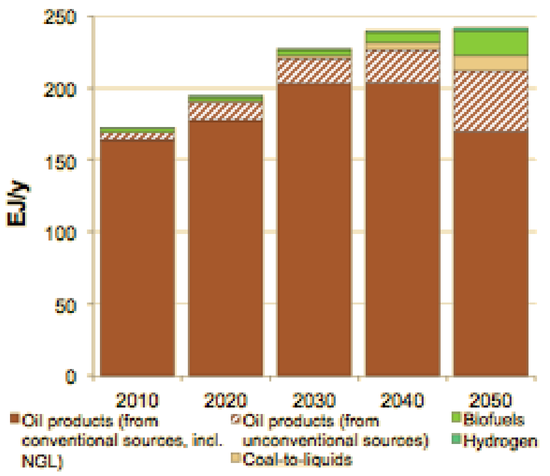


Figure 1.2. World liquid fuel supply in the Jazz Scenario (market-driven, little environmental constraints, selection through price and availability) [WEC, 2013].



1.1. EROI

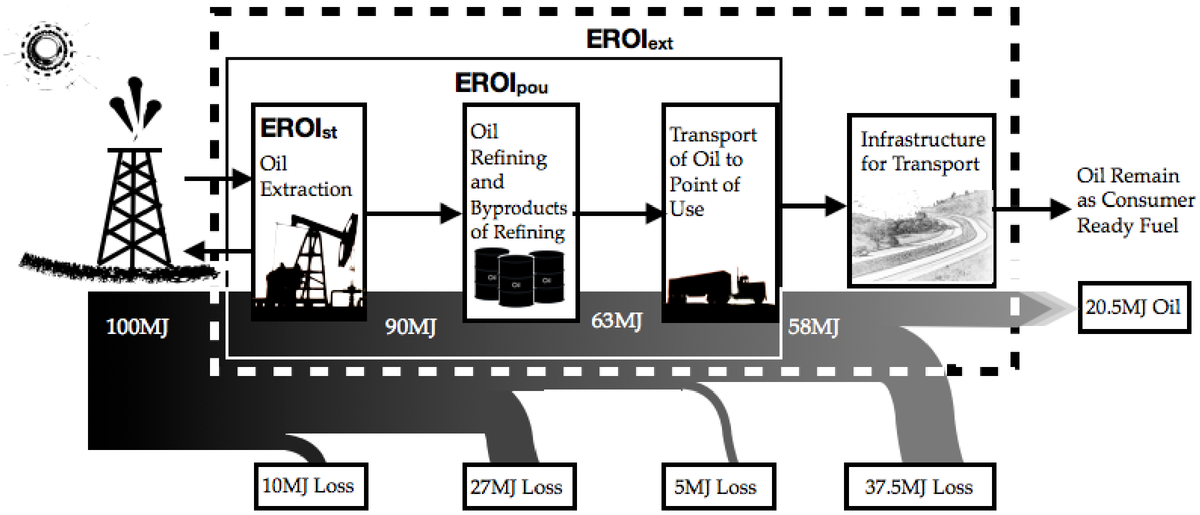
In order to measure the quality of energy resources, the term Energy Return on Energy Invested (EROEI or EROI) is often applied. The term determines the ratio of the energy returned to society compared to the energy required to get that energy (see Equation 1 below) [Hall et al., 2009].

$$EROI = \frac{\text{Energy returned to society}}{\text{Energy required to get that energy}} \qquad (1)$$

Another term often used is the Energy Requirement for Energy (ERE). The difference with EROI is just in formula: this term merely adds a surplus for energy consumption for energy [Blok, 2007]. By definition, the higher the EROI figure, the higher the quality of the resource, although the exact value depends on the boundaries incorporated (see Figure 1.3). For a good representation of energy consumption associated with the energy resource, the boundaries are preferred to be as exhaustive as possible. The EROI of energy resources has a physical and a technological component [Dale, 2010]. The physical component mainly consists of the type of resource, production processes, location and material costs for supporting infrastructure (as depicted in the schematic overview in Figure 1.3) [Dale, 2010]. The technological component consists of learning and efficiency factors [Junginger, 2005; Dale, 2010].

To give an indication: the EROI figures of the production phase of conventional fossil fuels are generally higher than 20, for renewables they range between 1 and 20 (not including hydropower, which has a relatively high EROI of >100). For unconventional fossil fuels they range between 1 and 10 [Dale, 2010; Murphy & Hall, 2010; Lambert et al., 2012].

Figure 1.3. Overview of EROI boundaries. Mine-mouth EROI includes solely the energy consumption of extraction, point-of-use EROI includes energy consumption of refining and transport and extensive EROI figures also calculate the energy consumption of infrastructure [Hall et al., 2009; Lambert & Lambert, 2013].

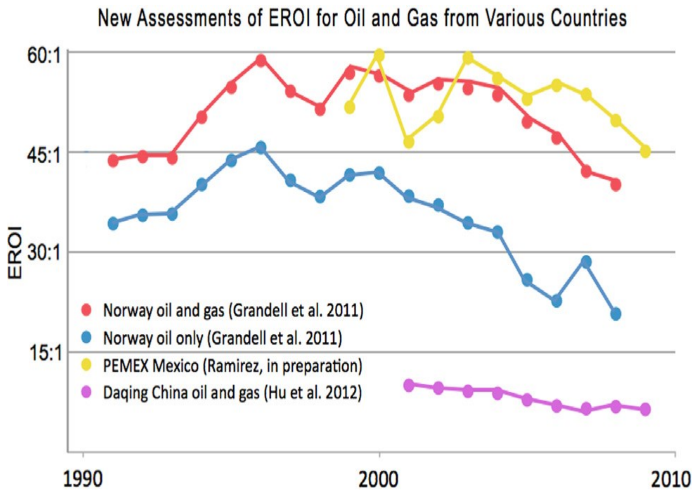


1.2. Previous studies

In recent years, many studies were done on historic and current EROI figures of various energy resources. Especially regarding energy use of fossil fuel production, a trend of average quality deterioration can be seen from Figure 1.4. This is caused by a switch to lower quality resources, which are less accessible, harder to produce or have less energy density [Murphy & Hall, 2010]. This would then lead to higher energy inputs for production.

Furthermore, there have been a lot of case studies on energy and emission profiles of unconventional fossil resources [Talve & Riipulk, 2001; Bartis et al., 2005; USBLM, 2007; Brandt, 2008; Brandt, 2009; Cleveland & O'Connor, 2010; Gavrilova et al., 2010; Aarna et al., 2011; Moerschbaecher & Day, 2011; Sell et al., 2011; Aucott & Melillo, 2013; Dale et al., 2013; Ibarren et al., 2013; Chang et al., 2014; Skone, 2014; Yaritani & Matsushima, 2014]. Besides these studies, there were also studies with a special regard for greenhouse gases associated with unconventional production [Brandt, 2011; Burnham et al., 2011; Howarth et al., 2011; Stephenson et al., 2011; Venkatesh et al., 2011; Laurenzi & Jersey, 2013]. There was however not yet a general overview of how the energy profiles of these unconventional fossil resources compare to conventional fossil resources, with the subdivision of production stages incorporated.

Figure 1.4. Various studies of EROI for oil and gas for several countries [Lambert et al., 2012].



Everts [2008] researched the influence of bitumen and shale oil market share growth on the global primary energy supply and greenhouse gas emissions, and mainly focusing on liquid fossil fuels. Emission and energy consumption figures were found to be a lot larger than their conventional counterparts, which resulted in a negligible market share for unconventional resource production under mitigation scenarios. It would be interesting to explore how a changing average quality for all fossil fuels would affect global emissions and primary energy supply figures in the future. Moreover, to fully understand these effects, you would need an analysis on what part of production mainly influences changing quality of these resources.

1.3. Goal of the research and relevance

The considerations in the previous section lead to the following research question:

What is the influence of changing energy inputs for the production of fossil fuels on global primary energy use and global CO_2 emissions until the year 2100?

Supporting sub-questions to give more insight in components of this research will be:

1. *What different fossil resource types can be distinguished and how do these differ in availability?*
2. *What are the different production processes of fossil fuels and what are corresponding energy inputs?*
3. *Which factors are influencing energy inputs for fossil fuel production?*
4. *What is the influence of indirect energy requirements on primary energy use and CO_2 emissions in a world with and without climate policy?*

This research will give more insight in the influence of resource depletion and structural change effects. This insight can, for example, be incorporated in integrated assessment models that are used to create future climate and energy projections. These models incorporate numerous factors that influence these aspects and give an understanding of how factors relate to each other. The integrated assessment model considered for this research is the model IMAGE, in which changes in energy inputs are analyzed in its energy sub-module TIMER [Stehfest et al., 2014]. This model incorporates the interactions of many socio-economic variables and is capable of showing and calculating with transformations in the energy system needed for a research on changing energy inputs for fossil resources production.

Especially with regard to technological detail in fossil fuel production processes and corresponding primary energy use allocation, the results of this research can provide insight in dynamic relations between resources. Policy makers could take the results in account when determining optimal energy and climate pathways. Moreover, it is important to have the best possible estimate of total CO_2 emissions and energy resource depletion in the future, as an underestimation might be harmful climate related events.

1.4. Outline

The research will be given a basic understanding through the Background information in section 2. This section will elaborate on what fossil resources are, what different types of conventional and unconventional can be distinguished and gives a few remarks on the TIMER model used for the methods.

Section 3 will describe the Methods, in which first the historic energy values of energy inputs are researched for the different fossil resource types, with later on in the section a description of how this will be used in combination with the TIMER model. Section 4 describes the Results and gives support for answering the research questions. Section 5 will test some of the assumptions made in the Methods section in a quantitative way with a Sensitivity analsysis, to give insight in uncertainties and sensitivities of the results. Section 6 will elaborate on and discuss the assumptions made in a more qualitative way than the Sensitivity analysis, with a general Conclusion in section 7.

Please also see the added References and Annexes for the detailed figures and sources of the research.

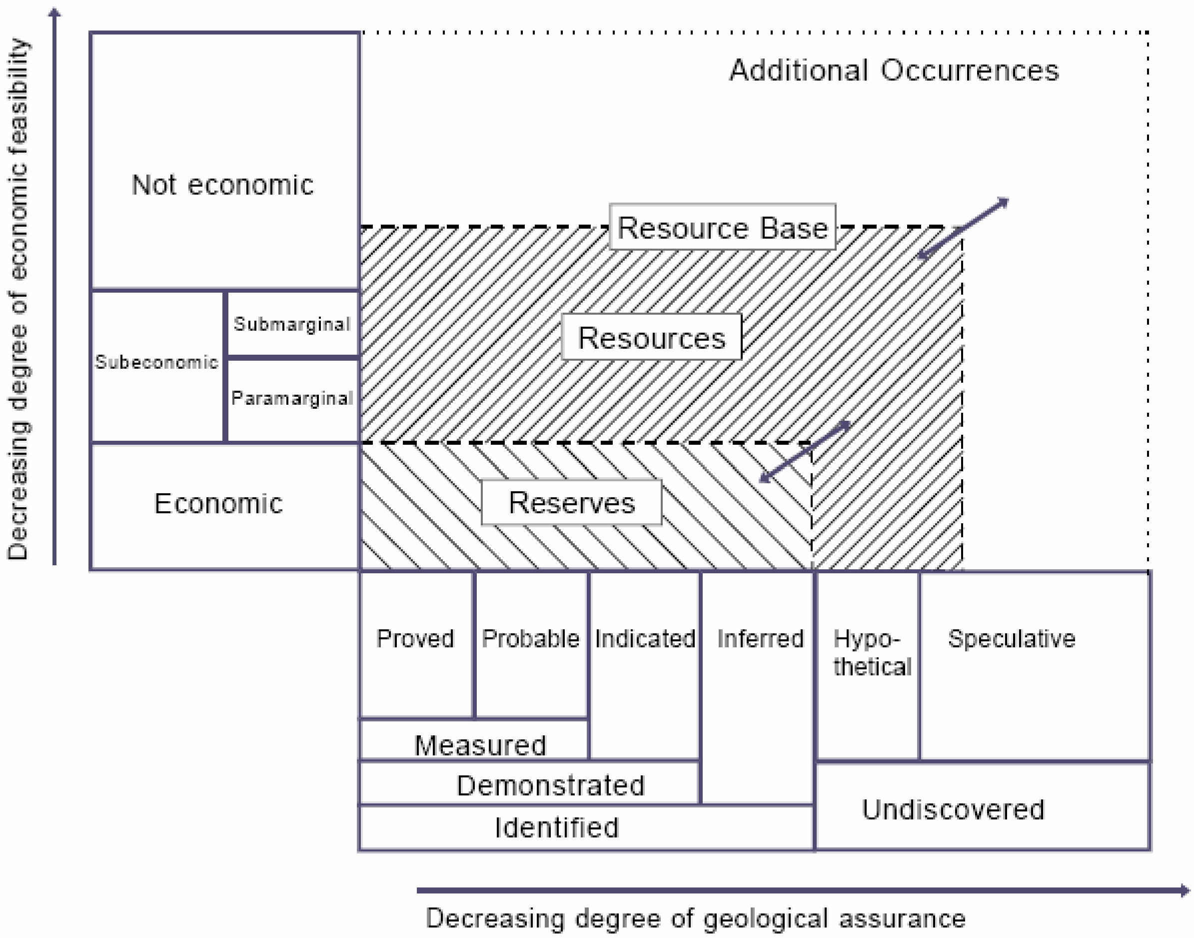
2. Background information

In this chapter, first an understanding of fossil resources and their subdivision is given. Afterwards there is a more in depth description of unconventional oil and gas and their production methods. Finally, an overview is given of how these aspects are incorporated in The IMage Energy Regional (TIMER) model as a basis for this research [Stehfest et al., 2014].

2.1. Fossil resources

In general fossil resources consist of coal types, oil types and gas types. Whether these are producible depends on the economic and technical feasibilities. As illustrated in the McKelvey diagram (Figure 2.1), these factors determine the classification between reserves, resources and occurrences of fossil resources.

Figure 2.1. Classification of energy resources. The horizontal and vertical axes give a range of geological and economic certainty, respectively [McKelvey, 1967; Rogner, 1997].



Reserves are quantities of the fossil resources that are geologically identified, demonstrated, measured or proven, and are economically feasible to recover, under existing economic and operating conditions [McKelvey, 1967; BP, 2010; GEA, 2012]. Resources are quantities of the energy resource that are not economically feasible to recover with current technology, but might be in the future. They consist of proven deposits and as of yet unfound deposits. [McKelvey, 1967; GEA, 2012] Additional occurrences consist of hydrocarbon or fissile materials of some recognizable form, but are not expected to become economically feasible with current technology [WEC, 1998; GEA, 2012].

Next to these classifications, the types of coal, oil and gas are further subdivided based on characteristics in chemical composition (viscosity, maturity), reservoir characteristics (permeability, pore space) and associated means of production and processing.

Conventional fossil resources are types of coal, oil or gas that have regular characteristics. For conventional oil and gas this means a high physical and chemical substance quality and a high reservoir quality. These types of substances are feasible to produce with commonly deployed technology.

Unconventional fossil resources are types of substances that have irregular characteristics, regarding physical and chemical substance quality, reservoir quality or both. These types of substances are not feasible to produce with commonly deployed technology and therefore require other kinds of production methods. This feasibility boundary is however constantly shifting with fluctuating hydrocarbon prices. To avoid confusion with currently produced substances and especially with future production of substances, the definition for conventional or unconventional oil and gas resources is based on physical characteristics.

Among unconventional types of oil resources are for example bitumen and extra heavy oil that have a high viscosity and lack (in-situ) mobility[1]. Shale gas belongs to unconventional types of gas that lack the presence of a permeable and porous reservoir. Biomass oil and liquids from coal liquefaction or gas transformation are often mentioned as sources for liquid hydrocarbons [GEA, 2012]. Even though these are produced from unconventional energy sources with unconventional methods, these sources will not be treated as fossil unconventional fossil energy resources.

[1] In-situ literally means “in the ground” and refers to resources that are still in their place of origin.

2.2. Unconventional oil types

An overview of the state of several unconventional oil types is given in Table 2.1, with a comparison to conventional oil.

Table 2.1. Overview of reserves, resources and production of conventional and unconventional oil types. Based on data by the Global Energy Assessment (GEA) [2012], unless otherwise indicated between brackets [USGS, 2000; USGS, 2008; Mohr & Evans, 2012; WEC, 2013; EIA, 2014].
*** One table in the GEA report [2012] states that the type of unconventional oil present in Venezuela is oil sands. Other tables in the report however state that the type of oil is extra heavy oil. Based on reports by USGS [2000; 2008], Mohr & Evans [2012], the WEC [2013], BGR [2013] and the EIA [2014], this was reconsidered and the amounts were allocated to extra heavy oil.**

	Conventional crude oil	Oil sands	Extra heavy oil	Oil shale
World reserves	5,477 EJ [USGS]	1,907 EJ	343 EJ*	1,485 EJ
World resources	6,161 EJ [USGS]	18,105 EJ	20,998 EJ*	16,856 EJ
Largest total resource base	Middle East	Canada	Venezuela*	U.S.A.
World cumulative production (2009)	6,647 EJ	130 EJ	354 EJ*	128 EJ
Global production (%) (2010)	31,100 Mb/y (97.4%) [EIA]	550 Mb/y (1.7%) [Mohr & Evans]	190 Mb/y (0.6%) [Mohr & Evans]	100 Mb/y (0.3%) [WEC]

For unconventional oil, the difference with conventional oil mainly exists within the substance quality, while for gas the difference in types mainly lies within reservoir quality and geological setting [GEA, 2012]. For substance quality of oil, there are again several indicators: viscosity, substance pollution (metals, sulfur, etc.) and maturity of the substance.

Viscosity determines the mobility of the substance, with viscous oil posing transportation difficulties [GEA, 2012]. This is a consequence of the material's deficiency in hydrogen, which can be overcome by enriching the substance with hydrogen in so called upgraders. Additionally, the substance is distilled from heavy metal and sulfur contaminations, a process also taking place in conventional refineries [Head et al., 2003; GEA, 2012]. For unconventional types this upgrading and distillation is slightly different and more extensive, producing Synthetic Crude Oil (SCO) from the raw hydrocarbon types [Brandt, 2011; GEA, 2012]. This process will be further explained in section 2.2.3.

The maturity of the substance is a good indicator of the aging of the hydrocarbon. All hydrocarbons form through decomposition of organic compounds: the higher the maturity, the more valuable, smaller fractions occur. When, for example, the semi-solid organic compound kerogen is not exposed to pressure and temperature, it remains in its original hydrogen deficient form. It can for example be present in shale strata, where it was buried quickly under low-oxygenic conditions. When enough heat is applied, the maturing process in-situ can be artificially reproduced, delivering valuable light hydrocarbons from the kerogen-containing shale rock. [GEA, 2012]

2.2.1. Oil sands

Oil sands (also tar sands or bituminous sands) is the common name for sand containing natural bitumen. It is important to distinguish between the container, oil sands, and the contained hydrocarbon, bitumen (approximately only 10% of the weight of oil sands, although it depends on the ore grade of the deposit). The bitumen needs to be separated from the sand mixture, after which a viscous and dense hydrocarbon remains, abundant in sulphur [Speight, 2008; Brandt, 2011]. Surface or shallow oil sands are mined after which bitumen is extracted through washing methods, while in deeper underground reservoirs bitumen is extracted with in-situ methods. Approximately 18% to 20% of total reserves can be produced with mining and extraction, the other 80% with in-situ methods [NEB, 2006; Alberta Government, 2013].

Oil sands mining and extraction

For surface or shallow oil sands to be mined, first the vegetation and overburden need to be removed. This is usually up to 60 to 75 meters. Deeper deposits are produced with in-situ methods [NEB, 2006; GEA, 2012]. Recovery rates of mined bitumen are typically 90% [GEA, 2012].

The surface or shallow oil sands are mined using hydraulic shovels, after which trucks transport the sands to central crushing and slurrying centers where hot water is added to lower the viscosity [ACR, 2004]. The sands are then transported through pipelines to extraction facilities, where bitumen froth is separated from sand. The froth is further treated to remove water and solids, producing natural bitumen [Brandt, 2011]. The bitumen is then either used as raw resource or further upgraded to SCO. The water and solid materials are returned and the mining area is ‘reclaimed’ (restored to the original situation) [GEA, 2012].

Improvements are expected in the integration of process steps and by increasing the quality of the bitumen. This is mainly directed at decreasing energy use in following process stages like upgrading [ACR, 2004; Brandt, 2011].

Oil sands in-situ production

There are several in-situ techniques for deeper oil sands deposits including the currently used Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD), and more innovative techniques as Toe-to-Heel Air Injection (THAI) and Vapor Recovery Extraction (VAPEX) [ADE, 2006; NEB, 2006].

CSS is the oldest form of in-situ oil sands production, sharing characteristics with the newer SAGD. They are both based on thermal recovery of bitumen by the injection of steam, reducing the viscosity of the hydrocarbons. Both are applied to thin layers of underground oil sands deposits, covering most of the oil sands underground occurrences [Flint, 2005]. The recovery rates depend on the method of production (periodically vs. continuous steam injection) and are 20-25% and 40%-60% of the in-situ bitumen respectively, with SO-ratios[2] of 4 and 2.5 respectively [ACR, 2004].

With CSS, high pressure steam is injected and heat 'soaks in' in the oil sands in the sealed off well [Ullman, 2007]. After that, first a period occurs in which the oil is autonomously produced through the pipe well, followed by a longer period of artificial pumping. If production declines the process is repeated. SAGD has a slightly different horizontal well configuration through which steam is continuously injected in the reservoir from the upper well, while bitumen flows into the lower production well. [ACR, 2004]

The THAI method is based on the injection of steam to pre-heat the bitumen and the injection of pressurized air to ignite the in-situ bitumen. The injection pipes are placed vertically and the production pipes horizontally. The combustion creates a front that in its turn heats the bitumen and causes it to flow to the horizontal production pipes. Cokes produced during the in-situ combustion are oxidized and its gases are co-produced. The product is partially upgraded and therefore reduces some of the energy demand for upgrading to SCO in later processes [Xia & Greaves, 2006; Ullmann 2007; Everts, 2008].

VAPEX is based on the same horizontal pipes as with the SAGD method, with the exception of using solvents instead of steam. These are typically gases as ethane, propane and butane. This method does not need steam and therefore reduces capital and energy costs, also because the solvents fulfill a double-role: in later production stages they serve as the necessary diluents to make the mixture less viscous. Furthermore, it does not need waste water treatment. The technology is however in early stage and only has had a few test projects [Moghadam et al., 2009].

THAI has a drastically lower energy use than currently applied technologies; VAPEX technology is not applied at the moment [Moghadam et al., 2009]. The main focus points for the in-situ technologies will be on the reduction of steam consumption and the increase of in-situ bitumen recovery rates [ACR, 2004]. Injection of high-pressure steam may be applied more often, as bitumen's viscosity reduction is exponentially related to temperature, resulting in higher flow rates. However, this also results in higher initial energy use and lower stability of the reservoir due to fracturing. [ACR, 2004; GEA, 2012]

2.2.2. Heavy oil and extra heavy oil

Heavy oil and extra heavy oil usually are classified in between conventional crude oil and natural bitumen. Heavy oil is mobile in-situ, which allows it to be produced without steam stimulation. Extra heavy oil is has some mobility in-situ, as the reservoir pressure provides a slight viscosity reduction.

[2] The Steam-Oil Ratio explains the volume in barrels of steam used to produce 1 barrel of raw bitumen.

This provides the opportunity to produce heavy oil and extra heavy oil quite conventionally, although upgrading and refining is required to create valuable light hydrocarbon products. [GEA, 2012]

Heavy oil and extra heavy oil production

The production method for heavy oil production that is often applied is the Cold Heavy Oil Production (CHOP) [NEB, 2006]. Because of the modest viscosity of the substance, a slight pumping and water flooding stimulation is enough to produce the hydrocarbon from the reservoir [GEA, 2012]. The production technique also allows for sand to be co-produced (in case of oil sands mixed with extra heavy oil instead of natural bitumen), although this is less often applied. This results in reduction of separation energy requirements. Other production steps are identical to conventional heavy oil production methods that are already often applied.

The hydrocarbons however need to be upgraded to produce SCO [ADE, 2006; NEB, 2006]. Recovery factors using CHOP are between 5% and 20% of the in-situ amounts. Future improvements are aimed at steam stimulation of the substance, making it less viscous thus increasing recovery factors. Other improvements relate to the deliberate co-production of the sand, reducing overall energy requirement [GEA, 2012].

2.2.3. Bitumen and heavy oil upgrading & processing

Bitumen and (extra) heavy oil are deficient in hydrogen, have increased concentrations of sulfur and heavy metals, and have a higher fraction of asphaltenes [Brandt, 2011]. As stated earlier, the hydrocarbons can either be upgraded or used as a raw resource. These downstream paths after production are therefore slightly different.

If upgrading takes place, first the bitumen is separated into smaller hydrocarbon fractions by increasing the H/C-ratio (hydrogen carbon ratio) through adding hydrogen. Furthermore, heavy fractions are rejected from the fraction mix [Flint, 2005; GEA, 2012]. Hydrogen production often requires steam reformation of natural gas, while the rejection of heavy hydrocarbon fractions is done through coking [Brandt, 2011]. Among different upgraders there are different coking techniques that eventually produce different mixes of products, but also require different energy inputs [ACR, 2004; Speight, 2008; AER, 2013]. This will be shown in section 3.2 and 4.2. At the moment there is no real use of cokes, as it is regarded unpractical in volume and a low-value product [ACR, 2004; Brandt, 2011]. Through hydro-treatment and purification, the end product is obtained, being deficient in 'bottom' heavy hydrocarbon compounds and with very low sulfur and heavy metal concentrations. This SCO is even seen as superior in quality compared to conventional crude oil (e.g. Brent crude oil) due to these characteristics [Brandt, 2011].

Raw bitumen can be transported after it has been mixed with diluent to reduce viscosity, producing *dilbit* (or *synbit*, when SCO is used as diluent) [Brandt, 2011; GEA, 2012]. The refining process of raw bitumen or heavy oil is however much more extensive than the SCO counterpart, as the substance contains a lot more heavier compounds and yields a less desirable product mix.

2.2.4. Oil shale

Shale oil (also kerogen) is the common name for oil contained in shale rock, also oil shale. It is a semi-solid fossil organic compound and is also deficient in hydrogen, making it a viscous compound. Kerogen is a form of immature oil and can be converted to high-value products through forms of pyrolysis, as it does not contain impurities like sulfur or heavy metal concentrations. Production methods differ between reservoir locations: surface and shallow deposits can be mined while underground deposits should be converted in-situ, as kerogen cannot be mobilized (e.g. with heat) [GEA, 2012].

Oil shale mining and retorting

For surface or shallow oil shale to be mined, first the vegetation and possible overburden need to be removed during preliminary stages. The surface or shallow oil shale deposits are afterwards mined and transported to central hubs. Before further processing can take place, the shale has to be crushed in small pieces. The kerogen needs to be decomposed afterwards in a process called 'retorting' [Taciuk & Turner, 1988; Schmidt, 2003; Brandt, 2009].

Basically, this process is a form of pyrolysis in which heat is added through combustion of the char and gases (the waste products of the retort process). Several designs have been proposed: the Alberta Taciuk Processor (ATP) [Taciuk & Turner, 1988; Taciuk et al., 1993] is one of the more advanced retort processes, having little shale waste and being mostly self-sufficient [Brandt, 2009]. The design is aimed at optimizing oil yield, as at higher temperatures slightly more gas or light liquid hydrocarbons are produced through the 'cracking' of the substance [Taciuk & Turner, 1988; Taciuk et al., 1993; Schmidt, 2003; Brandt, 2009]

After the retorting process, the shale oil is upgraded in a similar manner as described in upgrading section, to create a SCO-product abundant in hydrogen ready for refining. The spent shale is again brought back to the original mine for reclamation [Brandt, 2009].

Other processes comprise the Enefit140 and Enefit280 technology, deployed in Estonia mainly [Gavrilova et al., 2010; Aarna & Lauringson, 2011]. In this process a basic mining and retorting occurs, after which the products is not heavily upgraded. These processes are however mainly aimed at electricity production from shale, which is also an option, although this is outside the scope of this research, as it focuses on fossil fuel production.

Oil shale in-situ conversion methods

Until now, production methods were mainly suitable for surface and shallow deposits. Yet, some in-situ production methods are in the process of development [Bartis et al., 2005; Brandt, 2008]. A promising method is the Shell In-situ Conversion Process, most accurately described by Brandt [2008]. The process includes 4 major steps:

1. Creation of a freeze wall to prevent hydrocarbons from escaping the area and groundwater mixing with produced hydrocarbons.
2. Heating of the oil shale to create an in-situ retort, by means of electrical resistance heating.
3. Extraction of the hydrocarbons through pipeline pumping.
4. Remediation of the soil to wash out remaining hydrocarbons, actively preventing ground pollution.

First of all, some preliminary operations are performed to prepare the area above the deposit for in-situ shale oil production. A freeze wall is drawn up around the area by drilling a ring of wells: refrigerant is pumped into the wells to solidify rocks and soil (the 'wall'). This process takes about 1.5 to 2 years to complete. After the creation of the wall it will be maintained another 6.5 to 8 years during production [Brandt, 2008]. As the shale contains a lot of water, efficiency gains are made by first extracting the water from the soil, as this has a far higher heating requirement than the oil. [Brandt, 2011].

Heating wells are drilled, after which electrical resistance heating is applied for about 2 years [Burnham, 1993; Burnham & McConaghy, 2006; Brandt, 2008]. Similarly as described in the section above, the kerogen decomposes, after which the hydrocarbons are produced as vapors through production wells [Vinegar et al., 2013]. The products are fairly light, as heavy fractions remain in the reservoir or are cracked into lighter fractions [Brandt, 2008]. Post-production steps consist of remediation and restoration, in which the production area is cleaned up and remaining hydrocarbons are washed from the soil with water. The produced shale oil is afterwards upgraded and hydrogen-rich SCO remains [Brandt, 2008; Vinegar et al., 2013].

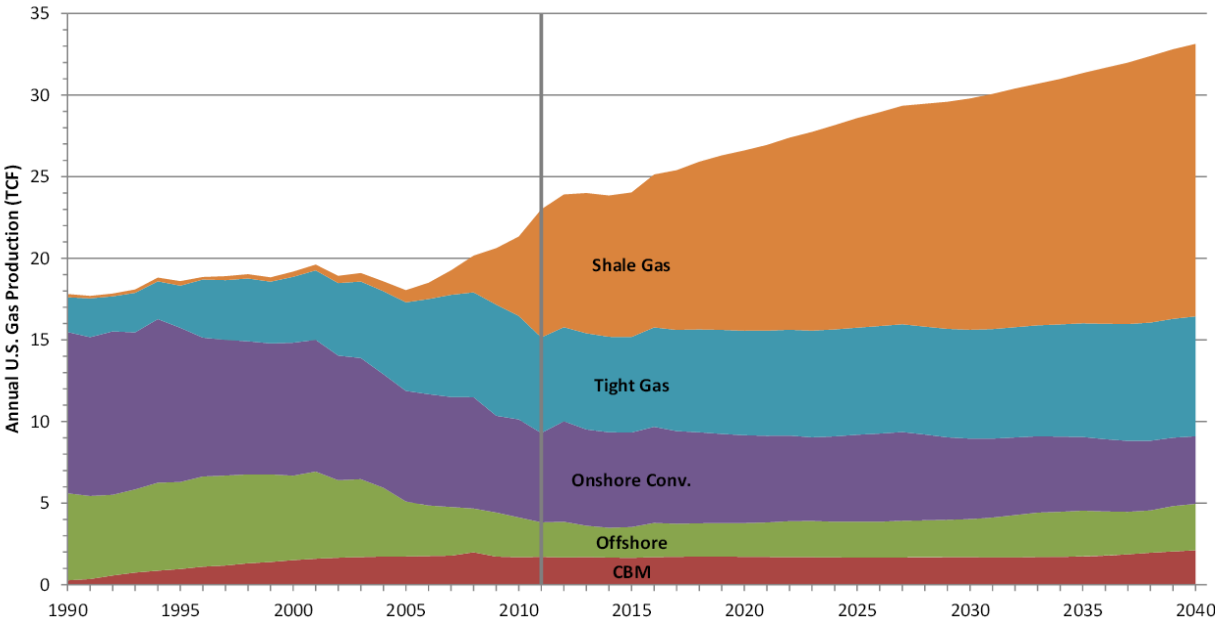
2.3. Unconventional gas types

An overview of the state of several unconventional gas types is given in Table 2.1, with a comparison to conventional gas. Moreover, Figure 2.2 gives historical data and a projection of the different conventional and unconventional gas types for the U.S. from 1990 to 2040 [Skone, 2014].

Table 2.2. Overview of reserves and resources of conventional and unconventional gas types. Based on data by the Global Energy Assessment (GEA) [2012], unless otherwise indicated between brackets [USGS, 2000; USGS, 2008].

	Conventional gas	Shale gas	Coalbed methane	Tight gas
World Reserves	5,021 EJ [USGS]	6,296 EJ	4,061 EJ	5,738 EJ
World Resources	7,193 EJ [USGS]	14,903 EJ	9,314 EJ	8,010 EJ
Largest total resource base	Russia	Russia	Russia/ U.S.A.	U.S.A.

Figure 2.2. Projection of gas types in the U.S., in 2011, figure used from [Skone, 2014]. Overall gas production is increasing, shale gas and tight gas gain in market share, while onshore and offshore conventional gas production decline slightly. CBM has gained a small market share until 2011 and remains steady.



As stated earlier, the difference between conventional gas and unconventional gas mainly exists within the reservoir quality and geological setting [GEA, 2012]. The reservoir quality unfolds around the permeability and porosity of the reservoir: in case these are high, the gas ‘flows’ easily through the reservoir.

Porosity indicates how much pore space there is in the reservoir: the larger the amount of pore space, the larger the amount of natural gas being possibly present in the reservoir. Permeability has to do with how these pores are connected to each other: a high permeability makes it easier to access the gas when a fraction of the pores is reached by drilling, through the interconnection of pore spaces. Besides these indicators, the gas can also be adsorbed to or solved in a substance. Next to energy for methods to reach and extract the basic products, an extra extraction action has to be performed to unbind or distill the gas, which obviously comes at a financial or energy expense. [GEA, 2012]

The geological setting determines how easy the gas can be accessed in terms of location, which is hard in case of deep and ultra deep occurring gas.

2.3.1. Shale gas

Shale gas is natural gas trapped in gas-bearing shale rock strata. The shale rock acts as the source ánd reservoir. The gas is present in the pore space, in vertical fractures or adsorbed to minerals or organic materials [GEA, 2012]. Conventional gas reservoirs normally are permeable and porous enough to let the gas ‘flow’ through the reservoir for production. Shale rock is however too fine-grained, with pore spaces too small and not well connected to be permeable [Slatt & O’Brien, 2011; GEA, 2012]. Gas from naturally fractured reservoirs can be produced, while other shale formations need artificial fracturing to produce gas. Although after fracturing the reservoir the gas flows to the production wells normally, ultimate gas recovery per well is fairly lower than with conventional reservoirs [Skone, 2014].

Shale gas production

For the shale gas to be produced, at first the extraction area is prepared with site clearing, road pavement and drilling rig preparation [Chang et al., 2014]. Afterwards, horizontal well drilling takes place, with the power engines and drilling fluids adding to the operations energy consumption.

Horizontal drilling is preferred over vertical drilling as this accesses the naturally occurring fractures in the shale [King, 2014]. Because of the impermeability, the shale gas will not flow autonomously to the wellbores [NEB, 2009]. Furthermore, the horizontal wells match the lay-out of the reservoir, as the shale strata are often under 100 meters thick [Wood et al., 2011]. The horizontal wells can stretch over 1 to 2 kilometers in length, being far costlier than their vertical counterparts [NEB, 2009].

After cementation of the well, hydraulic fracturing of the shale rock is applied. This is a process where pressurized water and chemicals are injected in the horizontal bore wells to create fractures in the shale rock surrounding the wells. The chemicals are added to keep the fractures open, allowing the natural gas to flow to the bore wells. [Aucott & Melillo, 2013]

Further operations comprise waste water treatment (to separate chemicals co-produced with the natural gas) and site control, before natural gas is transported from the facility through pipelines. The well completion is prone to fugitive methane emissions, leading to energy losses during the process.

Besides fugitives, a part of the produced gas is flared to reduce safety risks [Chang et al., 2014; Yaritani & Matsushima, 2014].

Advanced shale gas operations are based on multiple horizontal wells from the same bore hole to access more of the underground shale strata [Wood et al., 2011]. This leads to spreading out the overhead energy costs over a larger amount of produced gas, reducing the energy requirement per gas unit.

2.3.2. Coalbed methane

Coalbed methane (also CBM, coal seam gas and coal mine methane after desorption of the rock) is natural gas adsorbed to underground coal seam structures. Because of the adsorption, it lacks hydrogen sulfide, resulting in the produced gas being *sweet*, which reduces refining expenditures [GEA, 2012]. It can exist in natural fractures in the coal, in coal pore space and it can be absorbed by carbon in the coal [GEA, 2012]. As pressure increases with depth and therefore with coal rank[3], the capacity to store methane increases as well [USEPA, 2008]. As this gas poses a safety risk to underground mining operations, normally these gases are vented to the atmosphere through ventilation systems [USEPA, 2008].

Extraction is facilitated by the internal pressure in the reservoir or by extensive hydraulic fracturing of the structures, after which gas is produced through vertical or horizontal wells [USEPA, 2008; GEA, 2012].

Coalbed methane production

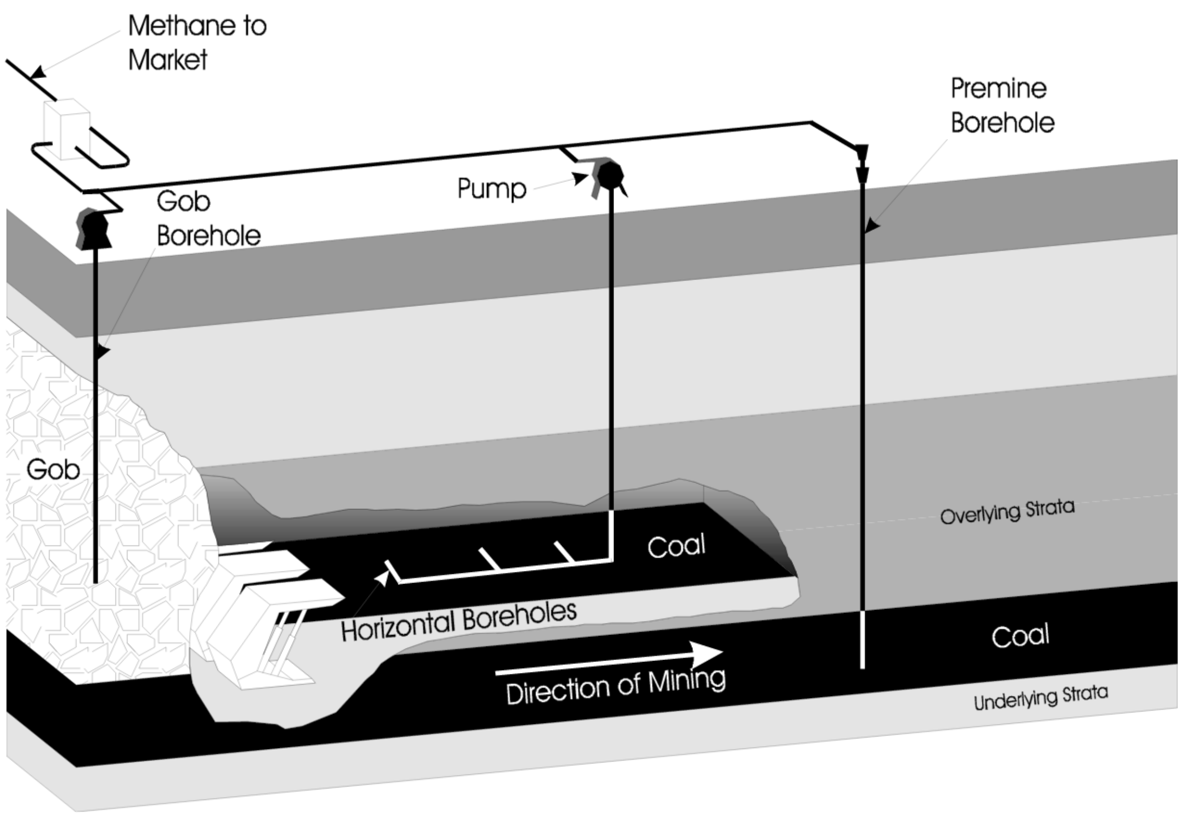
Historically, coal mine methane was not used for economic purposes. To counter the safety risk, coalmine operators first began installing ventilation systems to drain the mine gas. To increase economic benefits, drainage systems were set up that extracted a higher concentration of methane, greatly reducing the cost of ventilation systems and allowing the concentrated methane to be beneficially used. These drainage systems form the main techniques for the extraction of CBM employed nowadays [USEPA, 2008]. Several techniques are in development including vertical pre-mining gas extraction, gob well gas extraction and horizontal boreholes gas extraction (see Figure 2.3).

Vertical pre-mining wells are drilled from the surface into the coal seam several years in advance of underground coal mining [USEPA, 2008]. This technique ensures the produced methane is of high purity, as the product is not contaminated with ventilation air. The drilling technique is similar to that of conventional oil and gas wells, although it might need hydraulic fracturing to ensure the flow of

[3] The higher the coal rank, the higher the calorific value of the coal. This ranges from low coal rank products like peat, to high coal rank products like anthracite.

methane from the coal seam [USEPA, 2008; Aucott & Melillo, 2013]. Of the techniques employed, vertical pre-mining has the highest methane recovery and is therefore preferred in underground coal mining. This does not hold however for impermeable coal seams due to limited methane flows [USEPA, 2008].

Figure 2.3. The different techniques of coalbed methane production [USEPA, 2008].



Gob wells are drilled from the surface to a point slightly above the coal seam shortly before underground coal mining commences [USEPA, 2008]. As coal mining proceeds, areas around the coal seam fracture (the 'gob' area, see Figure 2.3) from which methane can be produced. Initially the recovery consists of large amounts of highly pure methane, followed by a mixture of methane and mine air requiring a form of gas upgrading [USEPA, 2008].

Other techniques comprise drilling horizontal boreholes from inside the coal mine, into the mined and unmined underground coal seams [USEPA, 2008]. These boreholes can stretch from 400 to over 1000 feet in length and produce a highly pure form of methane, although recovery rates are low.

For mitigation purposes, coalbed methane extraction could be combined with CO_2 injection to increase the amount of methane recovered and simultaneously storing CO_2 [Hendriks et al., 2004]. Studies have shown that of the various CO_2 storage possibilities, a combination with enhanced recovery of hydrocarbons is beneficial from an energy balance perspective, compared to other forms of CO_2 storage [Iribarren et al., 2013]. These types of processes would however be more on the side of mitigation strategies, and will therefore be left out of this research.

2.3.3. Tight reservoir gas

Tight gas is conventional natural gas trapped in tight sand (conventional) reservoirs, but with very low permeability. While it used to be classified as an unconventional source of gas, the distinction between conventional gas and tight gas is under discussion. For example, the U.S. Energy Information Administration does not list tight gas as an unconventional gas form anymore. In addition, besides a slight gas flow stimulation through reservoir fracturing, production is done by conventional means [GEA, 2012].

Tight gas production

Literature specifically on tight gas production processes is scarce, as the type of resource is increasingly categorized as conventional gas type [GEA, 2012; Skone, 2014]. Production methods are also conventional, except for the hydraulic fracturing of reservoirs to increase gas flow [GEA, 2012]. Studies show that energy requirements for tight gas extraction processes are in the order of magnitude of natural gas extraction, or possibly even lower [Sell et al., 2011; Lambert et al., 2012]. There are however indications that larger tight gas fields yield less natural gas per production area, which affects the energy use profiles of tight gas plays. In addition, fracturing tight gas reservoirs might increase the productivity of the gas fields on the expense of higher energy requirements and costs. [Sell et al., 2011]

2.3.4. Deep gas

Deep gas is classified in the GEA [2012] as gas located deeper than 4500 m. The reservoirs are highly pressurized and have high temperatures. Furthermore, they are technically challenging, as due to these characteristics the porosity and permeability is low. This implies additional reservoir fracturing might be needed for production. The ultimate recovery therefore is generally lower than conventional reservoirs, although as with tight reservoir gas, further production is done by conventional means. [GEA, 2012]

Deep gas production

As with tight gas production processes, literature on deep gas production is scarce, although energy consumption for these processes has been indirectly studied through financial balances [Gately, 2007; Moerschbaecher & Day, 2011]. The process of extraction is similar to conventional gas production, although energy and financial costs associated with drilling exponentially increase with depth [UDAC, 2009]. Deep water gas production has become attractive with the rise in oil and gas prices since the 1970s and ultra deep water gas production made up approximately a quarter of the total U.S. gas production in 2009 [Moerschbaecher & Day, 2011].

2.3.5. Aquifer gas

If methane is dissolved or dispersed in groundwater it is specified as aquifer gas. The methane has to be co-produced with the water, but as methane generally has a low solubility in water, the amounts that can be produced are low. At greater depths (under greater pressure) concentrations of methane in water can be higher, although the commerciality of these sources is questioned. It is expected that even with new extraction techniques only a small share of the total potential will be commercially viable since the water requires recycling and there is a low energy payback. Commercial projects might occur in regions in need for fresh water: by cleaning the water with water treatment the methane would be a valuable waste product. [GEA, 2012]

The production of these resources will however not be considered further in the research because of the low probability that the resource will be commercially adopted, and therefore even produced at all.

2.3.6. Methane hydrates

Methane hydrates (or gas hydrates, methane in clathrate structures) are solid crystalline substances consisting of water molecules forming a cage around the methane. These structures occur up to several hundreds of meters beneath the sea floor and have the highest concentrations in strata with high porosity and high permeability. They can be found in marine sediments along the continental coastlines, as well as the polar regions. The amount of potential resources of methane hydrates is vast and exceeds other forms of unconventional gas by several orders of magnitude. The proposed production methods are however not proven to be commercially viable yet, or expected to be in the near future. Possible pathways for future extraction could be dissociation of the hydrate by depressurization, thermal stimulation or injecting alcohol-like chemical compounds. [GEA, 2012]

The production of these resources will not be considered further in the research as it is expected that the resource is not commercially viable for a long time (until 2100) and because of other production uncertainties.

2.4. TIMER model

In this research, the TIMER model will be used to analyze the future developments in energy supply of fossil energy carriers, emissions resulting from the fossil energy sector and fossil fuel prices. The IMage Energy Regional (TIMER) model has been developed to explore different scenarios in a broader context of the IMAGE global environmental assessment framework [Stehfest et al., 2014]. It is an energy-system simulation model with a main objective in analyzing long-term trends in energy demand and supply [de Vries, 2001; van Vuuren, 2007].

Both business as usual and climate change mitigation scenarios are run and analyzed. Climate change mitigation strategies are simulated by adding a carbon tax, which results in price effects leading to a potential substitution of energy carriers. Areas of particular interest are the types of fossil energy carriers in TIMER, their corresponding producible amounts and pathways of these energy carriers from production to end product.

The model describes 26 world regions and 12 primary energy carriers, further subdivided in secondary energy carriers. TIMER simulates the trends in energy demand, energy conversion and energy supply in their respective sub-modules. The recently published IMAGE 3.0 documentation provides more information on TIMER, and the broader links with the IMAGE model [Stehfest et al., 2014].

Table 2.3. Producible oil categories in TIMER [Mulders et al., 2006]. Categories 1-7 consist of conventional oil types, while categories 8-12 consist of unconventional oil types.
*** Category 11 is supplemented with a part of 'conventional' oil from enhanced recovery of category 6. Please see the report by Mulders et al. [2006] for a more in depth explanation.**

Oil			
Category	**Cat. #**	**Global amount in TIMER**	**Types**
Production 1970-2010	1	5.06 ·10^3 EJ	Conventional gas Natural gas liquids
50% proven recoverable reserves	2 (I)	3.08 ·10^3 EJ	
50% proven recoverable reserves	3 (I)	3.08 ·10^3 EJ	
Estimated additional reserves	4 (II)	4.61 ·10^3 EJ	
Additional speculative resources	5 (III)	4.49 ·10^3 EJ	
Enhanced recovery	6 (IV)	3.37 ·10^3 EJ	
Extra expensive	7	1.78 ·10^3 EJ	
Unconventional recoverable reserves	8 (V)	1.76 ·10^3 EJ	Oil sands (bitumen) Heavy crude oil Extra heavy crude oil Oil shales(shale oil)
Unconventional resources	9 (VI)	4.43 ·10^3 EJ	
Additional unconventional resources	10 (VII)	7.75 ·10^3 EJ	
Additional occurences *	11 (VIII)	51.77 ·10^3 EJ	
Extra expensive category	12	6.56 ·10^3 EJ	

Table 2.4. Producible gas categories in TIMER [Mulders et al., 2006]. Categories 1-7 consist of conventional gas types, while categories 8-12 consist of unconventional gas types.
*** Category 11 is supplemented with a part of 'conventional' oil from enhanced recovery of category 6. Please see the report by Mulders et al. [2006] for a more in depth explanation.**
**** Category 11 is also supplemented with methane hydrates.**

Gas			
Category	**Cat. #**	**Global amount in TIMER**	**Types**
Production 1970-2010	1	$2.50 \cdot 10^3$ EJ	Conventional gas
50% proven recoverable reserves	2 (I)	$3.25 \cdot 10^3$ EJ	
50% proven recoverable reserves	3 (I)	$3.25 \cdot 10^3$ EJ	
Estimated additional reserves	4 (II)	$5.33 \cdot 10^3$ EJ	
Additional speculative resources	5 (III)	$5.15 \cdot 10^3$ EJ	
Enhanced recovery	6 (IV)	$2.40 \cdot 10^3$ EJ	
Extra expensive	7	$1.80 \cdot 10^3$ EJ	
Unconventional recoverable reserves	8 (V)	$5.65 \cdot 10^3$ EJ	Shale gas Tight gas Coalbed gas Deep gas
Unconventional resources	9 (VI)	$10.80 \cdot 10^3$ EJ	
Additional unconventional resources	10 (VII)	$16.16 \cdot 10^3$ EJ	
Additional occurences *,**	11 (VIII)	$760.73 \cdot 10^3$ EJ	
Extra expensive category	12	$3.26 \cdot 10^3$ EJ	

Table 2.5. Producible coal categories in TIMER [Mulders et al., 2006]. Categories 1-7 consist of hard coal (underground coal), while categories 8-14 consist of brown coal (surface coal).

Coal			
Grade	**Cat. #**	**Global amount in TIMER**	**Types**
Hard coal - cumulative production 1971-2007	1	$1.86 \cdot 10^3$ EJ	Hard coal
Hard coal - proven recoverable reserves	2 (A)	$23.01 \cdot 10^3$ EJ	
Hard coal - additional recoverable resources	3 (B)	$117.71 \cdot 10^3$ EJ	
Hard coal - additional identified reserves	4 (C)	$25.01 \cdot 10^3$ EJ	
Hard coal - 20% of additional resources	5 (D)	$39.45 \cdot 10^3$ EJ	
Hard coal - 80% of additional resources	6 (E)	$157.79 \cdot 10^3$ EJ	
Hard coal - backstop (10% addition resource)	7	$36.30 \cdot 10^3$ EJ	
Brown coal - cumulative production 1971-2007	8	$1.27 \cdot 10^3$ EJ	Brown coal
Brown coal - proven recoverable reserves	9 (A)	$2.22 \cdot 10^3$ EJ	
Brown coal - additional recoverable resources	10 (B)	$10.05 \cdot 10^3$ EJ	
Brown coal - additional identified reserves	11 (C)	$1.28 \cdot 10^3$ EJ	
Brown coal - 20% of additional resources	12 (D)	$3.94 \cdot 10^3$ EJ	
Brown coal - 80% of additional resources	13 (E)	$15.76 \cdot 10^3$ EJ	
Brown coal - backstop (10% addition resource)	14	$3.32 \cdot 10^3$ EJ	

2.4.1. TIMER fossil resource categories

Fossil resource amounts in the TIMER model are based on cost-supply curves of the fossil energy carriers [Stehfest et al., 2014]. They extend from relatively cheap categories with a high production certainty to expensive categories with a high uncertainty of production, to account for differences between reserves, resources and occurrences as described in section 2.1. These considerations make up 12 categories for oil, 12 categories for gas and 14 categories for coal, based on definitions by

Rogner [1997] and TNO [Mulders et al., 2006]. For oil and gas, categories 1-7 are conventional and 8-12 are unconventional. In the case of coal, categories 1-7 correspond to hard coal, while 8-14 are used for brown coal. Compared to oil and gas, the two coal types are not classified as conventional and unconventional. The spectrum of reserves, resources and occurrences is shown for each of the three fossil resources in Table 2.3, Table 2.4 and Table 2.5. Corresponding category numbers are given in the middle column, the original Rogner and TNO category numbers given between brackets. The specified resource types per category are shown in the last column.

2.4.2. TIMER fossil resources, fuels and energy carriers

In the previous section fossil resources were subdivided in oil, gas and coal resources, and in conventional and unconventional occurrences. These conventional and unconventional categories can be produced simultaneously and are therefore substitutable for one another. Production of these resources occurs in the supply sub-module of the TIMER model, according to the demand for solid, liquid and gaseous fuels calculated in different parts of the model. The demand for these fuels is supplemented with an indirect demand of these fuels, needed for production and transformation of the fuels. The solid, liquid and gaseous fuels have coal, oil and gas as their main respective feedstock, although this transformation covers cross-over production of fuels, representing processes of liquefaction and gasification for example. [Stehfest et al., 2014]

The TIMER model aggregates the spectrum of different fossil fuels into only 3 types: solid, liquid and gaseous fuels [de Vries et al., 2001]. It distinguishes demand for light-liquid fuels and heavy liquid fuels to a certain degree, although it is based on an exogenously determined fraction. Furthermore, the model has cokes as a separate energy carrier for the steel model. The indirect energy demand for the production of these fuels is however the same for each produced unit, with an average added fraction [de Vries et al., 2001]. This means that on average the production of for example diesel and heavy oil products has the same indirect energy requirement.

3. Methods

This chapter will describe the methods used to assess the influence of upstream energy losses in fossil fuel production on global energy and CO_2 emissions. As the different fossil resource types were elaborated in the Background information, the energy inputs were assessed for each of these types. An overview of the different steps in the methods is given in Figure 3.1.

Figure 3.1. Overview of the methods used in the research. The figures 3.1, 3.2, 3.3 and 3.4 stand for the corresponding sections in the methods.

- **3.1 Assessment of energy inputs in conventional resource production and downstream processing, based on the IEA extended balances [IEA, 2014]**
  - Coal, conventional oil and conventional gas
  - Downstream processes are assumed to be the same for both conventional and unconventional
  - Energy allocation is based on supply chain (instead of oil to oil etc., see text for explanation)
- **3.2 Assessment of energy inputs in unconventional resource production**
  - Oil: oil sands surface and in-situ production, extra heavy oil, oil shale surface and in-situ production and upgrading of bitumen, based on case studies
  - Gas: shale gas, coalbed methane, tight gas, deep gas and hydraulic fracturing, based on case studies
- **3.3 Trend extrapolation of conventional resource production and downstream processing**
  - Based on best fitting (R^2) and most realistic trend
  - Unconventional resource production follows trends of global average production and downstream processing
- **3.4 Implementation in the TIMER model and analysis of baseline and mitigation scenarios**
  - Input/ output approach regarding energy inputs of resource production
  - Addition of indirect energy to direct energy
  - Analysis of baseline scenarios: comparison with the original model
  - Analysis of mitigation scenarios: comparison with the original model

First, the conventional production energy inputs were analyzed in section 3.1, using the IEA extended balances. The energy inputs of each process were allocated to solid fuel, liquid fuel and gaseous fuel production and divided by their total energy use to get an upstream energy input per unit.

Afterwards, in section 3.2, the energy inputs of production processes of unconventional oil and gas were obtained using case studies on each of the fossil resource types, also on a per unit basis.

In section 3.3 the data of section 3.1 and 3.2 was brought together. As the historical data for conventional coal, oil and gas was available, each of the production methods was analyzed for trends to extrapolate the energy inputs of these processes to future production, based on the amounts present in the TIMER cost-supply curve categories. The trends were also applied to unconventional oil and gas production processes. As described earlier, the amounts in the unconventional fossil resource categories in TIMER are the sum of the amounts of all unconventional resource types of oil or gas (i.e. oil sands and shale oil). To account for these differences, the production energy inputs of each of these fossil resource types were used to calculate a weighted average for each of the TIMER unconventional categories.

After the assessment of the energy inputs in each of TIMER categories, the results from 3.3 were implemented in the TIMER model and baseline and mitigation scenarios were run to analyze the effect of additional energy demand in fossil fuel production, previously not taken into account.

3.1. Energy analysis of conventional resource production & resource processing

The IEA extended balances served as the primary input for analysis of energy related to production methods of conventional energy resources [IEA, 2014]. The data comprises 138 countries and 3 former nations, 67 products, 95 energy flows and time steps from 1960 to 2010. As the data is governed by the OECD, data collection of some (Non-OECD) countries only started in later years.

3.1.1. Energy carrier aggregation and allocation

To ensure a fit with the TIMER model, the data had to be aggregated to the 26 TIMER regions (section 2.4). Furthermore, the products in the IEA extended balances were aggregated to five energy carriers for simplification and to fit the TIMER model: 1) solid fuel inputs (comprising of hard coal, brown coal and other coal), 2) liquid fuel inputs (crude oil and oil products), 3) gaseous fuel inputs (natural gas and gas works gas[4]), 4) electricity and 5) renewables (mainly bio- and waste-products). The IEA reports several products to their corresponding main feedstock, instead of allocating on a physical basis[5] [IEA, 2013]. This assumption will be discussed in section 3.2 and in the Discussion. The IEA reports separate figures for oil shale and oil sands, which have been left out of the aggregation to prevent mixing up conventional and unconventional (only for the model not in section 4.1 which shows the trends over the years).

[4] From the 2011 edition onward, gas works gas is allocated to coal and coal products in the IEA balances [IEA, 2008; IEA, 2013]. To ensure the calibration of the TIMER model, the old allocation to gas is used.
[5] For example: petroleum coke is allocated to oil products, despite of its solid phase.

3.1.2. Production methods and downstream fuel processes: aggregation and allocation

Besides the TPES[6], the flows in the IEA database were subdivided into transformation flows and energy use flows, according to the IEA labels in the database [IEA, 2014]. The TPES of coal, oil and gas for each region was corrected for the statistical differences. Transformation flows consist of fuels used for the primary or secondary conversion of energy to make derived energy products. Energy use flows are the combined total of energy consumption during fuel extraction and plant operations of transformation activities [IEA, 2010].

Together with flows related to electricity generation, heat generation and renewables, these flows make up the difference between the TPES and the Total Final Energy. As this research only considers the fossil fuel production, several flows regarding electricity, heat and biofuels production were left out[7]. Additionally, the TIMER model explicitly incorporates blast furnace energy use and transformation in the steel industry, and was therefore also left out of the calculation [Stehfest et al., 2014].

Table 3.1. Transformation and energy use flows in this research. Unless energy carrier input is given (between brackets), all energy carriers within the flow are allocated to the energy carrier in the first column.
*** Allocated according to method given above. For a further explanation of the processes, please see the IEA extended balances [2014] and other documentation [IEA, 2010].**

	Transformation flows (T)	Energy use flows (E)
Hard coal & Brown coal	T-coke ovens	E-coke ovens
	T-patent fuels	E-patent fuels
	T-BKB fuels[5]	E-BKB fuels[8]
		E-coal mines
		Distribution loss (Coal)
Oil	T-refineries	E-refineries
	T-coal liquefaction	E-coal liquefaction
	T-gas-to-liquids	E-gas-to-liquids plants
	T-petrochemical plants	Distribution loss (Oil)
Gas	T-gas works	E-gas works
	T-blended natural gas	E-liquefaction/regasification plants (LNG)
		Distribution loss (Gas)
Oil & Gas		E-oil and gas extraction*
All	T-non-specified*	E-non-specified*

[6] Total Primary Energy Supply, is calculated as 'indigenous production + imports – exports – international marine bunkers – international aviation bunkers ± stock changes'.
[7] The TIMER model was corrected for these changes, as historically these are incorporated in the model. Please see section 3.4 too.
[8] BraunKohle Briketten, or Brown Coal Briquettes which is a processed brown coal product.

All of the production and processing related energy flows (25 in total) are allocated to the corresponding producible coal, oil and gas products, as can be seen in Table 3.1.

Allocation of shared flows such as "E-oil and gas extraction is based on the ratio of useful output of each of the products. For example, when in a region the useful output of oil and gas is 15 GJ and 5 GJ respectively, and the gas use flow E-oil and gas extraction is 1 GJ, then 0.75 GJ is allocated to oil and 0.25 GJ is allocated to gas. When determining fractions (see Equations 2 to 7 below), both oil and gas have a fraction of 5% gas per unit useful output (0.75 GJ/15 GJ = 0.25 GJ/ 5 GJ = 5%).

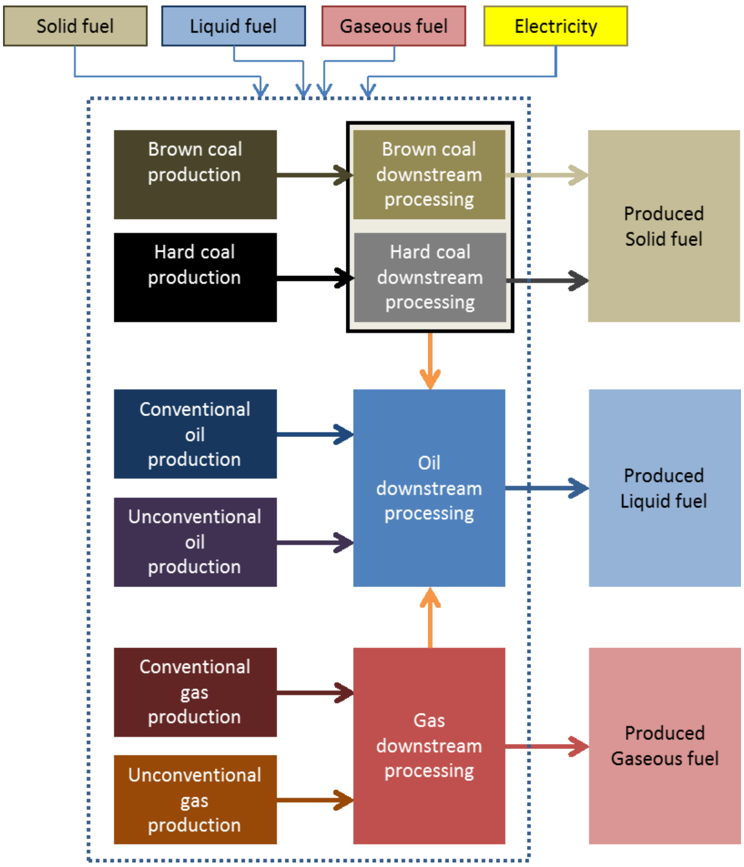
Table 3.2. Transformation and energy use flows in the original TIMER model. All of the energy carriers are allocated to the one specified in the first column, regardless of what activity they occur in. As an example: coal used in gas works is allocated to coal, oil used in coal transformation is allocated to oil.
*** E own-use in the IEA world energy balances consists of the sub-parts E-coal mines, E-oil and gas extraction, E-blast furnaces, E-gasworks, E-biogas plants, E-coke ovens, E-patent fuels, E-BKB, E refineries, E coal liquefaction, E-LNG, E-gas-to-liquids, E-electricity, CHP and heat plants, E-pumped storage, E-nuclear industry, E-charcoal, E-non-specified and distribution losses [IEA, 2013; IEA, 2014]. For the TIMER model, E-blast furnaces was taken out of this summation [Stehfest et al., 2014].**
**** T-non specified in the IEA world energy balances consist of the sub-parts T-other transformation and T-charcoal plants [IEA, 2014].**
***** T-coal transformation in the IEA world energy balances consist of the sub-parts T-blast furnaces, T-coke ovens, T- patent fuels and T-BKB [IEA, 2014]. For the TIMER model T-blast furnaces was taken out of this summation [Stehfest et al., 2014].**

	Transformation flows (T)	Energy use flows (E)
Hard coal & Brown coal		E-own use (Coal)*
	T-non-specified (Coal)**	E-non-specified (Coal)
	T-coal transformation (Coal)***	E-coal transformation (Coal)***
	T-gas works (Coal)	E-gas works (Coal)
	T-gas-to-liquids (Coal)	Distribution loss (Coal)
Oil		E-own use (Oil)*
	T-non-specified (Oil)**	E-non-specified (Oil)
	T- refineries (Oil)	E- refineries (Oil)
	T-coal transformation (Oil)***	E-coal transformation (Oil)***
	T-gas works (Oil)	E-gas works (Oil)
	T-gas-to-liquids (Oil)	Distribution loss (Oil)
Gas		E-own use (Gas)*
	T-non-specified (Gas)**	E-non-specified (Gas)
	T-coal transformation (Gas)***	E-coal transformation (Gas)***
	T-gas works (Gas)	E-gas works (Gas)
	T-gas-to-liquids (Gas)	Distribution loss (Gas)

In the original TIMER model these flows were allocated slightly different, as shown in Table 3.2. Most importantly the energy carrier inputs were not allocated based on processes, but on energy carriers. Simply stated, oil use is allocated to the oil balance, regardless of in which processes it occurred. Besides, there were a few minor double countings in using distribution energy loss, refining energy and coal transformation energy, since these were already incorporated in the variable Energy for own use. The last difference is that energy for non-fossil industry related activities was also incorporated in the variable Energy for own use, which the new method corrects for.

For oil and gas it is important to distinguish between production and downstream processes as production energy values are specifically for conventional resource types, while downstream processes are the same for conventional as well as unconventional types (with already upgraded products). An overview of these paths and their correlations is given in Figure 3.2. As can be seen from this figure, energy inputs for coal production and processing can be aggregated as all of the data is are already known; energy inputs for conventional oil and conventional gas should initially be kept separately from their downstream paths.

Figure 3.2. Overview of different process steps for fuel production, within the system boundary as marked by the dotted line. Solid fuel, liquid fuel, gaseous fuel and electricity are assumed inputs or outputs of every process. Conventional and unconventional oil and gas share the same downstream process and are substitutable for each other. Brown coal and hard coal have different processes and applications but both form solid fuel after processing. For illustration purposes the cross-over processes of coal-liquefaction and gas-to-liquids is given in the orange arrows. There are in fact many other cross-overs through by-products, transformations and conversions.



In order to determine what fraction of energy is used in the production and downstream resource processing (the Energy Requirement for Energy fraction [Blok, 2007]; ERE), a general format was used, as shown in Equations 2 to 7 on the next page. Simply put, the indirect energy use is represented by the sum of energy inputs of each production method or process, divided by the total useful output of each energy carrier. The formula for the Energy Requirement for Energy is given in Equation 7. Example box 1 on the next page gives an example of the aggregations and calculations of the energy fractions from the IEA extended energy balances.

$$E_{s\ for\ x} = \frac{-\sum E_{s\ for\ x} - \sum T_{s\ for\ x}}{\sum TPES_x - \sum T_{s\ for\ x} - \sum T_{l\ for\ x} - \sum T_{g\ for\ x} - \sum T_{e\ for\ x} - \sum T_{o\ for\ x} - \sum E_{s\ for\ x} - \sum E_{l\ for\ x} - \sum E_{g\ for\ x} - \sum E_{e\ for\ x} - \sum E_{o\ for\ x}} \tag{2}$$

$$E_{l\ for\ x} = \frac{-\sum E_{l\ for\ x} - \sum T_{l\ for\ x}}{\sum TPES_x - \sum T_{s\ for\ x} - \sum T_{l\ for\ x} - \sum T_{g\ for\ x} - \sum T_{e\ for\ x} - \sum T_{o\ for\ x} - \sum E_{s\ for\ x} - \sum E_{l\ for\ x} - \sum E_{g\ for\ x} - \sum E_{e\ for\ x} - \sum E_{o\ for\ x}} \tag{3}$$

$$E_{g\ for\ x} = \frac{-\sum E_{g\ for\ x} - \sum T_{g\ for\ x}}{\sum TPES_x - \sum T_{s\ for\ x} - \sum T_{l\ for\ x} - \sum T_{g\ for\ x} - \sum T_{e\ for\ x} - \sum T_{o\ for\ x} - \sum E_{s\ for\ x} - \sum E_{l\ for\ x} - \sum E_{g\ for\ x} - \sum E_{e\ for\ x} - \sum E_{o\ for\ x}} \tag{4}$$

$$E_{e\ for\ x} = \frac{-\sum E_{e\ for\ x} - \sum T_{e\ for\ x}}{\sum TPES_x - \sum T_{s\ for\ x} - \sum T_{l\ for\ x} - \sum T_{g\ for\ x} - \sum T_{e\ for\ x} - \sum T_{o\ for\ x} - \sum E_{s\ for\ x} - \sum E_{l\ for\ x} - \sum E_{g\ for\ x} - \sum E_{e\ for\ x} - \sum E_{o\ for\ x}} \tag{5}$$

$$E_{o\ for\ x} = \frac{-\sum E_{o\ for\ x} - \sum T_{o\ for\ x}}{\sum TPES_x - \sum T_{s\ for\ x} - \sum T_{l\ for\ x} - \sum T_{g\ for\ x} - \sum T_{e\ for\ x} - \sum T_{o\ for\ x} - \sum E_{s\ for\ x} - \sum E_{l\ for\ x} - \sum E_{g\ for\ x} - \sum E_{e\ for\ x} - \sum E_{o\ for\ x}} \tag{6}$$

$$Total\ ERE_x = \left(E_{s\ for\ x} + E_{l\ for\ x} + E_{g\ for\ x} + E_{e\ for\ x} + E_{o\ for\ x}\right) + 1 \tag{7}$$

x: $product\ energy\ carrier\ x\ (i.e.\ oil\ products, methane, BKB\ fuels)$

T: $transformation\ flows\ (if\ negative, other\ fuels\ are\ net\ produced)\ [ktoe]$ [9]

E: $energy\ use\ flows\ [ktoe]$[9]

$TPES$: $TPES\ corrected\ for\ statistical\ differences\ [ktoe]$

s, l, g, e, o: $primary\ or\ secondary\ energy\ inputs\ from\ solid\ fuels, liquid\ fuels,$
$gaseous\ fuelz, electricity\ and\ other\ inputs\ [ktoe]$

ERE: $Energy\ Requirement\ for\ Energy$

This aggregation and allocation eventually results in energy production profiles for the production of coal, production of conventional oil, production of conventional gas and their respective downstream paths. These downstream paths are the same for unconventional oil and unconventional gas. Moreover, the amount of energy allocated to the production of each unit oil and gas is the same, as Energy for oil and gas extraction does not distinguish between oil and gas.

[9] It is important to note that Transformation and Energy flows in the IEA balances are already given as negative flows. To enhance clarity the equation states another minus sign.

An important notion to these conventional figures is that they already represent the total energy inputs in the whole economy and therefore all indirect energy requirements are included. They can therefore be considered to be top-down figures. These do not represent individual processes, and can not be directly compared to for example unconventional production energy profiles that are gathered through process analyses. The individual process figures will be gained through reversing the Input/ Output method, as explained in section 3.4.

Example box 1. Calculation example of energy fractions from the IEA extended balances [2014].

A modified world energy balance [IEA, 2014] is given in Table 3.3. The energy inputs per unit coal production are calculated by the taking the energy use for coal mines and dividing it by the subtotal of coal (also the sum of the corrected TPES and the net transformation flows, which are negative, minus the energy flows). The figures in between the first brackets in Equations 8 to 12 on the next page indicate those energy inputs. After that, the downstream processes need to be taken in account, representing the net sums of energy for other coal processes, distribution losses (only coal) and coal transformation inputs (second brackets). Finally, an already determined amount is added for the non-specified energy and transformation (as they are shared flows, an allocation over all energy carriers was done), basically by dividing these energy flows by the sum of the subtotals of coal, oil and gas. The total energy needed upstream to produce a coal product is 0.0494 $Mtoe_{inputs}/Mtoe_{coal}$.

Table 3.3 Modified world energy balance 2011 of the IEA [2014].

World energy balance 2011 (in million tonnes of oil equivalent)					
Supply and consumption	Coal & coal products	Crude oil & petroleum products	Gas & gas works gas	Electricity	Other energy
TPES	**3781.19**	**4136.20**	**2790.09**	**0.35**	**2421.12**
Statistical differences	-162.22	6.55	6.45	-0.38	-0.52
Corrected TPES	**3618.97**	**4142.75**	**2796.54**	**-0.03**	**2420.60**
Gas works	-7.23	-3.85	3.78	-	-0.09
Petroleum refineries & petro chemistry	-	-29.80	-0.85	-	-
Coal transformation	-58.44	-2.68	-0.04	-	-0.07
Liquefaction plants	-16.79	8.08	-9.48	-	-
Other transformation	-0.07	1.57	-3.84	-	-0.55
Energy use coalmines	-36.78	-5.32	-0.18	-11.70	-1.41
Energy for oil & gas extraction	-	-15.72	-162.01	-18.11	-3.54
Energy for other coal processes	-27.17	-0.06	-0.06	-0.89	-1.12
Energy for other oil processes	-0.09	-189.00	-48.19	-20.75	-20.26
Energy for other gas processes	-1.46	-0.16	-39.61	-1.01	-0.20
Other energy use	-0.01	-3.21	-17.51	-6.98	-31.24
Distribution losses	-3.29	-8.93	-19.73	-154.41	-20.49
Subtotal	**3467.34**	**3893.68**	**2498.88**	**-213.88**	**2341.63**
Electricity plants, CHP plants, heat plants, etc.	---	---	---	---	---
TFC	---	---	---	---	---

See next page for the equations.

(8) $$E_{coal\ for\ coal} = -\left(\frac{-36.78}{3467.34}\right) - \left(\frac{-27.17 - 3.29 - 58.44}{3467.34}\right) + 0.0000 = 0.0363$$

(9) $$E_{oil\ for\ coal} = \left(\frac{-5.32}{3467.34}\right) - \left(\frac{-0.06 - 2.68}{3467.34}\right) + 0.0002 = 0.0025$$

(10) $$E_{gas\ for\ coal} = \frac{-0.18}{3467.34} - \left(\frac{-0.06 - 0.04}{3467.34}\right) + 0.0022 = 0.0022$$

(11) $$E_{electricity\ for\ coal} = \frac{-11.70}{3467.34} - \left(\frac{-0.89}{3467.34}\right) + 0.0007 = 0.0043$$

(12) $$E_{other\ for\ coal} = \left(\frac{-1.41}{3467.34}\right) - \left(\frac{-1.12 - 0.55}{3467.34}\right) + 0.0032 = 0.0041 \quad +$$

$Total$ 0.0494

ERE 1.0494

3.2. Energy analysis of unconventional resource production

To calculate the energy inputs for unconventional resource production on a unit basis, energy inputs were gathered and analyzed on energy balances of production processes. These are different from the energy balances mentioned earlier in the IEA statistics: these balances merely are an overview of energy inputs and outputs of each process. These will be referred to energy profiles further on to avoid confusion.

Afterwards the energy inputs of each production process were divided by the average total output of each process to have a bottom-up energy requirement fraction for the production of each unconventional resource. The methods for the calculation of the energy profiles of unconventional resource production are subdivided between oil types and gas types. The methods are briefly described; for the energy profiles please see Annex B.

3.2.1. Unconventional oil production methods

The production methods of unconventional oil are described from the resource in-situ until the end product, also known as the cradle-to-factory gate method [Durucan et al., 2006]. For oil sands and extra heavy oil these processes consist of steps between the in-situ occurrence to the distilled bitumen, after which upgrading is needed to convert the hydrocarbon to Synthetic Crude Oil (SCO). For shale oil these processes consist of the stages between the in-situ occurrence and the end product SCO, as retorting and upgrading of the hydrocarbon is incorporated in the production process already.

After the production of SCO, it is assumed that further downstream processing has an energy requirement that is the same for unconventional and conventional resources. This leads to an end conversion of SCO to an oil or liquid hydrocarbon product, solid hydrocarbon product, gaseous hydrocarbon product. More detailed information on the energy profiles of the unconventional oil case studies is given in Annex B.

Oil sands

The data aggregation was based on four case studies, comprising of an oil sands mining project [Esso & ImperialOil, 2006; Everts, 2008], oil sands plant statistics from the Alberta Energy Regulator [2013], an in-situ SAGD project [Petro-Canada, 2005; Everts, 2008] and a THAI in-situ production project [Orion 2003; Everts, 2008; Greaves et al., 2012]. As stated in section 2.1 approximately 20% of all reserves and resources are surface deposits; the other 80% therefore should be produced with in-situ methods.

The oil sands plant statistics give information on the balance of material flows in volume or mass, of which four are based on production and three were based on production plus upgrading incorporated. The net energy flows[10] are divided by the total bitumen output (in case of production) or by the total synthetic crude oil output (in case of production plus upgrading). Process gas and coke have negative net energy flows, indicating they are co-produced. The statistics don't give specific process steps. It was however assumed that the information comprises all the process steps. The four cases based on production were supplemented with the oil sands mining project energy profile [Esso & ImperialOil, 2006; Everts, 2008].

After the addition of the upgrading energy values to each of the cases (see section *Upgrading* below for the upgrading energy profile), these five cases were added to the three cases of production plus upgrading, forming the basis of oil sands surface production energy values. An average of the eight case studies was taken for the energy profile of surface oil sands production plus upgrading.

As SAGD is the most advanced currently deployed technology for in-situ oil sands production and THAI is a promising future technology for in-situ production, two case studies of these technologies will form the basis for the energy profile of in-situ oil sands production. The energy use of SAGD is comparable in order of magnitude to currently deployed surface and shallow oil sands projects. The THAI technology has significantly lower energy use figures, although it is expected that this technology will gain a large market share in the future [Ullmann, 2007; Everts, 2008; Greaves et al., 2012]. As current oil sands projects mostly focus on surface and shallow deposits, in-situ production will not take place for a while. These low energy values for pilot projects of THAI therefore seem justified, as it will take some time before these will be deployed. Energy inputs for in-situ oil sands production are based on an average of SAGD and THAI energy inputs.

All the reported energy profiles are described from in-situ occurrence to the stage of synthetic crude oil being transported outside the production system. The energy profile is afterwards aggregated to the four energy carriers solid fuel, liquid fuel, gaseous fuel and electricity, being either negative or positive in value. The weighted average of surface oil sands (20%) and in-situ oil sands (80%) is taken to calculate the energy values for the total production of oil sands resources.

Extra heavy oil

Cold Heavy Oil Production, or CHOP, is the main production method for heavy oil types and does not require any unconventional method. It is therefore assumed that the energy inputs are the same as for conventional oil and are therefore regionally dependent, although probably with a higher total energy input. Section 3.3 will give more information on future trends of conventional oil that will be used as a basis for extra heavy oil production. Extra heavy oil production is supplemented with the process step 'Pipeline transport' from oil sands production, to account for long distance

[10] Converted with data from IPCC [2006].

transportation of slightly viscous bitumen. As the bitumen requires upgrading, the average upgrading energy values (see section *Upgrading* below) are added to the extra heavy oil production energy inputs to complete the process cycle from in-situ occurrence to synthetic crude oil. The energy inputs are afterwards aggregated to the four energy carriers solid fuel, liquid fuel, gaseous fuel and electricity, being either negative or positive in value.

Upgrading of bitumen and heavy oil

For the upgrading of bitumen and heavy oil, three cases were used. The three upgraders are based on different methods and therefore give a good indication of the average energy consumption in the upgrade process. The Nexen Long Lake Project upgrader is efficient with resources, as it uses its asphaltene residues for gasification, through which energy gains are achieved. Therefore there is no net coke output [Brandt, 2011; AER, 2013]. Another process is the Shell Scotford upgrader, which adds extra H_2 in hydrotreatment of the bitumen, to create larger volumes of SCO [Brandt, 2011; AER, 2013]. This requires more natural gas, but gives no net coke output, being higher in energy use. The last process is the Sturgeon upgrader, based on the original upgrading, having a higher internal bitumen consumption, but generating net process gas and cokes [AER, 2013]. The net energy flows were divided by the total synthetic crude oil output per process and were furthermore aggregated to the energy carriers solid fuel, liquid fuel, gaseous fuel and electricity, being either negative or positive in value. The data does not give specific process steps; it was however assumed that the information comprises all the process steps.

Some of the produced bitumen is transported and mixed with diluent. As explained in section 2.2, when utilizing the 'dilbit' mix in refining, these feedstocks require a lot more refining energy inputs. It is therefore assumed that the process paths of upgrading & conventional refining and non-upgrading & non-conventional refining have similar orders of magnitude in their energy inputs towards end-products. This means that to produce a product of liquid fuel, regardless of the process path, it has the same aggregated upstream energy inputs as calculated.

Shale oil

The data aggregation was based on five case studies, consisting of an oil shale surface mining project (ATP, see section 2.2) with a low and high energy input scenario [Brandt, 2009], an in-situ conversion energy input estimate [Bartis et al., 2005] and an oil shale in-situ conversion project with a low and high energy input scenario [Brandt, 2008]. Due to the lack of information on what part of the total resources is producible with surface mining and in-situ extraction techniques, the same ratio as for oil sands is assumed, being 20% surface mining and 80% in-situ extraction [NEB, 2006; Alberta Government, 2013].

The ATP was chosen because it is a more advanced production method for surface oil shale mining [Brandt, 2009]. For the energy profile of surface oil shale mining, the average of the low- and high-energy case is taken. The upgrading is already incorporated in the energy profile.

The Shell in-situ conversion method is a promising method for in-situ shale oil production and forms the basis for the in-situ resources [Brandt, 2008]. The separate case studies for the in-situ conversion method were not entirely comparable, as in the Bartis et al. study [2005] only the energy input estimate for in-situ conversion is given, lacking other process steps. The process step of production was averaged over the three studies, while for other process steps the average was taken from the low and high energy case by Brandt [2008]. The upgrading is already incorporated in the energy profiles.

All the reported energy profiles are described from in-situ occurrence to the stage of synthetic crude oil being transported outside the production system. The energy profile is afterwards aggregated to the four energy carriers solid fuel, liquid fuel, gaseous fuel and electricity. The weighted average of surface oil shale mining (20%) and in-situ conversion (80%) is taken to calculate the energy values for the total production of shale oil.

3.2.2. Unconventional gas production methods

The energy requirement for production methods of unconventional oil is calculated based on the resource in-situ until the end product, also known as the cradle-to-factory gate method [Durucan et al, 2006]. For all unconventional gas types this is from in-situ resource to the stage of the extracted natural gas. After the production of natural gas it is assumed that further processing is included in the conventional life cycle, for which downstream processes and corresponding energy figures as described in section 3.1 are assumed. This leads to an end conversion of natural gas to a gas or gaseous hydrocarbon product or an oil or liquid hydrocarbon product. The given energy profiles are based on the energy inputs for the total production well. Allocations on a unit of end product basis are made with the use of the estimated ultimate recovery per well. The energy profiles are based on the amount of end products and are subdivided in the four energy carrier inputs solid fuels, liquid fuels, gaseous fuels or electricity. Other energy carriers were allocated to the previous four proportionally. More detailed information on the energy profiles of the unconventional gas case studies is given in Annex B.

Shale gas

The data for shale gas production is based on four case studies, consisting of three Marcellus shale gas production studies [Aucott & Melillo, 2013; Dale et al., 2013; Yaritani & Matsusima, 2014] and a shale gas production project in China [Chang et al., 2014]. The Dale et al. study [2013] gives a high and a low energy case, which are both used as a separate case in this research. These studies formed the basis for shale gas production, as well as the for the energy profile of the hydraulic fracturing process steps, that form input for other unconventional gas production processes.

The separate case studies were not entirely complete, as some case studies reported certain process steps and others did not. To compensate for missing data, additional energy requirement was assumed for missing process steps (as described in Table 3.4) by averaging the energy use of the process steps across studies.

Table 3.4. Process steps in shale gas production, per case study. A: [Yaritani & Matsushima, 2014], B: [Aucott & Melillo, 2013], C: [Chang et al., 2013], D: high energy case in [Dale et al. 2013], E: low energy case in [Dale et al., 2013].
*** Process steps 3 and 7 are first summed, and then averaged.**

	Process step	Occurrence in case study
1.	Infrastructure construction	A,B,C,D,E
2.	Operations (plant energy use)	A
3.	Operations (drilling, well completion, etc.)*	A,B,C,D,E
4.	Operations (hydraulic fracturing)	B,C
5.	Embodied energy in fracking chemicals	A,B,C
6.	Post-fracturing waste water treatment	B,D,E
7.	Fugitive natural gas*	A,B,C,D,E
8.	Pipeline construction	A,B

Another important notion is the estimated ultimate gas recovery (EUR) per well. The difference with unconventional oil types (for which this is not really accounted for) is that for gas, the majority of energy consumption occurs during preparation of wells. With unconventional oil, energy consumption occurs in the processing of the fuel. This means that the ultimate recovery, by which all of the 'overhead' energy costs are divided, influences the upstream energy consumption per unit of gas more than it would per unit of oil. Reported estimated ultimate gas recoveries are 3.0 Billion cubic feet (Bcf) in the reports by Aucott & Melillo [2013] and Yaritani & Matsushima [2014], and 2.42 Bcf and 3.81 Bcf for the high and low energy cases by Dale et al. [2013]. For the case by Chang et al. [2014], an EUR of 3.0 Bcf was assumed.

All the reported energy profiles are described from in-situ occurrence to the stage of the extracted natural gas. After averaging the energy inputs per process step and dividing total inputs by the EUR, they were aggregated to the four energy carriers solid fuel, liquid fuel, gaseous fuel and electricity.

Coalbed methane

As data for energy profiles of coalbed methane production is scarce and no dominant technique has emerged as of yet, the energy inputs in coalbed methane production are assumed to be the same as for conventional gas, although with a higher total energy input. These figures will therefore be regionally dependent. Section 3.3 will give more information on future trends of conventional gas that will be used as a basis for coalbed methane production.

The majority of current techniques is based on well drilling and makes use of the internal pressure of the reservoir. The produced gas serves as an input for the plant's energy needs and the operations will only be performed if commercial. Stand-alone operations aimed specifically at gas production cannot make use of benefits of simultaneous coal production (e.g. destabilizing the coal seam for gas release, see section 2.3) and will need other methods of gas flow stimulation. The conventional energy inputs are therefore supplemented with the hydraulic fracturing process steps 4 to 6 of Table 3.4 and their energy inputs. The estimated ultimate gas recovery of coalbed methane reservoirs is however projected to be substantially lower (1.15 Bcf instead of 3.00 Bcf [Skone, 2014]). The fracturing energy inputs are therefore adjusted to the appropriate estimated gas output.

Tight reservoir gas

Tight reservoir gas is increasingly categorized as a conventional resource type, and is therefore assumed to share energy input values with conventional production, although with a higher total energy input. These figures will therefore be regionally dependent. Section 3.3 will give more information on future trends of conventional gas that will be used as a basis for tight reservoir gas production. The tight gas reservoirs however need a form of gas flow stimulation to achieve production, for which the hydraulic fracturing process steps as described in the shale gas section are used. The conventional energy inputs are supplemented with the hydraulic fracturing energy inputs, but adjusted for the estimated ultimate gas recovery of tight gas production wells (1.20 Bcf instead of 3.00 Bcf in Marcellus shale [Skone, 2014]).

Deep gas

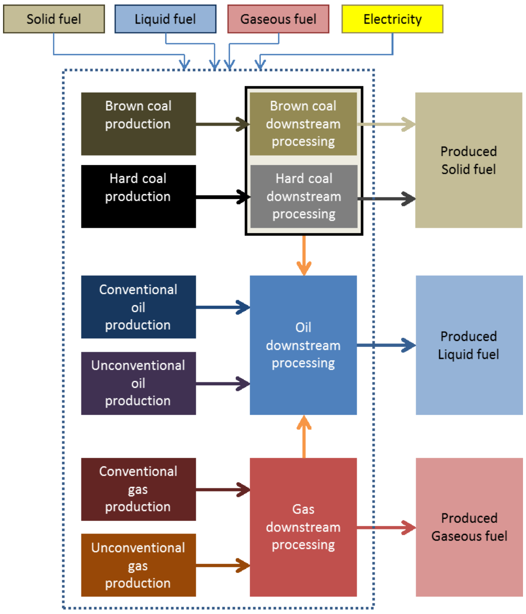
As described in section 2.3, deep gas production occurs with conventional production techniques, although financial and energy costs are substantially higher than currently deployed conventional gas operations. For this reason, literature specifically on deep gas operations is scarce and future conventional gas production energy inputs are assumed, as will be described in section 3.3. These figures will therefore be regionally dependent. As a large part of conventional production already consists of deep gas (see section 2.3 on deep gas), the additional energy needs for potential fracturing are assumed to be already incorporated in the conventional energy inputs.

3.3. Trends in energy for conventional and unconventional production methods and processes

In section 3.1 the energy inputs for coal, conventional oil and conventional gas production were assessed, as were the energy inputs for downstream coal processing, oil processing and gas processing. In section 3.2, the energy inputs for the production of the different unconventional oil and gas types were assessed. To ensure the fit with the TIMER model (and its cost-supply curve categories), an aggregation of these figures was made.

A simplified overview of the system used for the model was given in Figure 3.2 in section 3.1 (also see Figure 3.3 as a reminder). Every segment of the system has its own set of average energy inputs or outputs and are, except for assessed figures for unconventional oil and gas production, also regionally dependent. Due to a lack of data on unconventional hydrocarbon production within different regions, it was assumed that the basic methods of production are the same for all regions. The preferences to produce hydrocarbons with certain (different) energy inputs reflect the state of technology or fuel prices in that specific region. These values will however fluctuate through time: as briefly touched upon in the Introduction, two aspects will influence the energy for the production of useful fuels. The physical aspect (also depletion effect in the TIMER model) has a tendency to increase the energy requirements for production, as the resources become less accessible, lesser in quality (e.g. ore-grade) and harder to produce. The technological aspect over time has a tendency to decrease the energy requirements for production as efficiency progresses through learning effects. Besides these aspects there could also be substitution between energy inputs, because of the state of technology, fuel prices in the market or other aspects.

Figure 3.3. Overview of different process steps for fuel production, within the production system boundary as marked by the dotted line. A more detailed description is given with Figure 3.2, of which this is a copy.



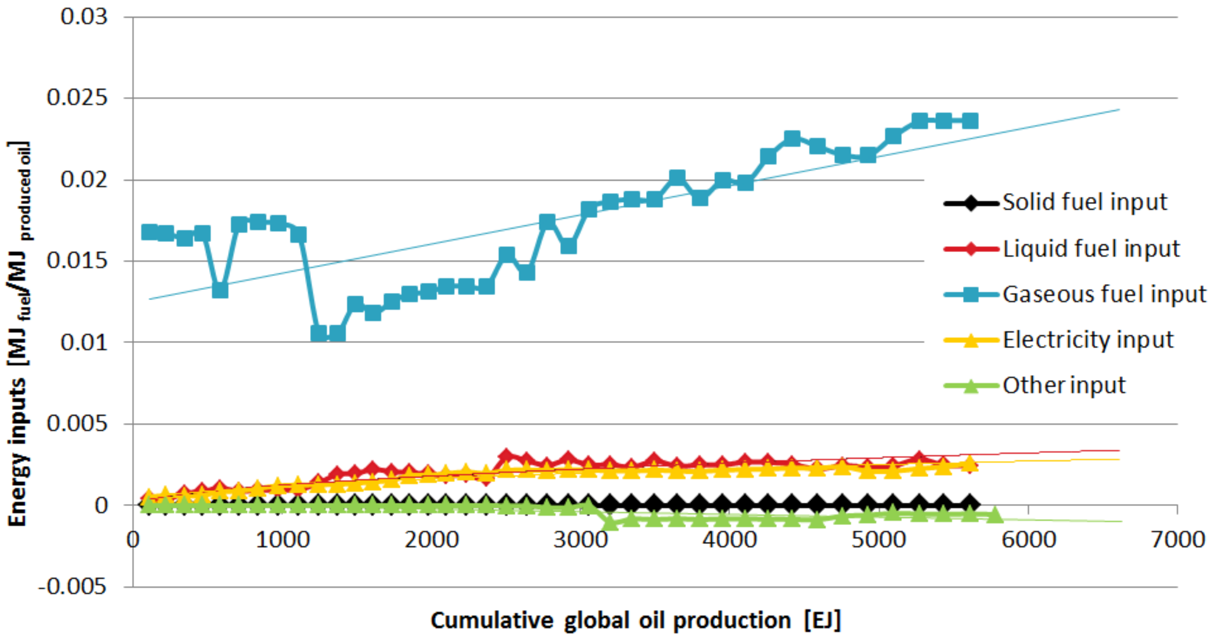
3.3.1. Trends extrapolation

These considerations lead to the fact that production energy requirement trends for different input types can be different for the same process. It is therefore necessary to separately measure these trends for each process, per energy input type, per region and related to depletion (physical aspect) and/or time (technological aspect). The energy inputs of conventional fossil fuel production, and their trends through time, already incorporate these two effects. The effect that can be seen from measuring the trends, is merely the net influence on energy use of these two effects. It was chosen to relate the energy input trends to depletion (and therefore cumulative production) of the resources.

An additional time dependent efficiency measure will be introduced in the Sensitivity analysis to see what the influence on energy and emissions would be, if efficiency would progress at a higher rate than already incorporated in the net effect of energy input trends.

Each of the energy input types within processes was plotted against the cumulative production of the corresponding producible resource, as calculated from the IEA extended balances [IEA, 2014]. Afterwards, trend lines were plotted to find the best fit. The types of trends considered were linear relations, logarithmic relations, power relations and exponential relations. The equations were taken from the trend lines with the highest R^2 values. This could lead to different types of trends within the types of energy inputs for the same process (e.g. the amount of gaseous fuel input in oil production could increase linearly over time, while the oil input would increase logarithmically over time, for a certain region). The equations of the best fitting trend lines were thereafter used to extrapolate the energy carrier inputs to the amounts of cumulative production expected in each of the TIMER categories for each region [Mulders et al., 2006] (see Figure 3.4; see section 2.4 for the TIMER resource categories).

Figure 3.4. Energy inputs for global oil production, with their corresponding trends and extrapolations. A linear relation gives the best-fitting trend line for the gaseous fuel inputs (blue line), while logarithmic relations have a clear fit for liquid fuel and electricity inputs (red and yellow lines). The world average gaseous fuel input for oil production decreased drastically after the second oil crisis in 1979, explaining the sudden drop of the blue line in the graph.
*** Important notion: these energy inputs represent only the production without any downstream processes.**



Some of the best fitting trend lines however led to extremely high values for the energy inputs in the later categories, because of the vast amounts present in those categories. These trend lines were therefore reconsidered for the trend line with the second highest R^2 value, or third. Afterwards, values for categories 1 to 7 were compared with the world averages to check for reliability: regional data with too much deviation from the world average was replaced with the world average values for each category.

This was also the case for South Africa, Brazil and the former Soviet Union regions (Ukraine, Kazakhstan and Russia), since historical energy use was very high for coal or oil production, due to liquefactions processes. For these regions, a drastic energy input decrease trend was chosen from the year 2011 onward, that converged towards the world average energy input.

3.3.2. Unconventional TIMER categories

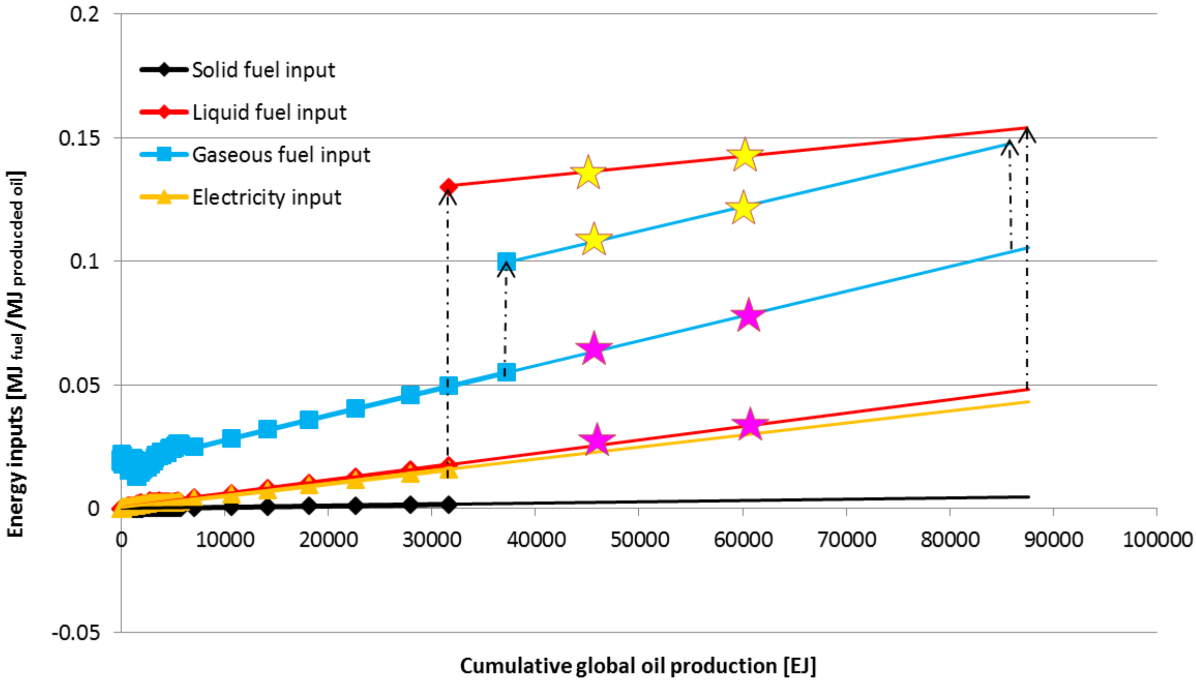
The unconventional production energy input values are assumed to follow the same slope as conventional, starting from a higher initial value (see Figure 3.5). The values and displacement in the figures are fictional, but the yellow stars represent the liquid and gaseous fuel energy inputs of unconventional categories in this example. The world average trends were taken for the unconventional energy input extrapolation, as there is no regional distinction between production processes yet. In the future it would be likely that some regions gain a competitive advantage in the production of certain unconventional fossil resources, although those exact regions cannot be specified yet.

The assessed energy inputs as described in section 3.2 were taken as the initial values. As each region has a different mix of oil types in the reserves and resources, the initial values for each region are based on a weighted average of the amount in each category. This leads for example to Canada’s energy production values being mainly based on oil sands, whereas Latin America’s production values are mainly based on Venezuela’s extra heavy oil deposits.

For extra heavy oil, coalbed methane, tight gas and deep gas, the energy production values are based on the conventional extrapolations, as shown in Figure 3.5. The pink stars represent the higher category gas and oil energy inputs. These values are based on the extrapolated trend line energy input values, in case the resources would be conventional.

The production steps within the unconventional process were extrapolated based on conventional production trends; the processing steps (upgrading and retorting) were extrapolated based on the conventional downstream processing trends. The reason is the similarity of techniques: upgrading and retorting show a resemblance to for exampling oil refining. Probably these processes will go through similar efficiency and learning trends in the future.

Figure 3.5. Global oil production energy inputs plotted against cumulative global oil production. Trend lines (fictional) are extrapolated to the maximum amount of producible oil resources. To calculate the unconventional energy inputs extrapolation, the slopes of the conventional trend lines are used as a basis. Effectively, this leads to a vertical displacement of the trend line. The pink stars represent energy input values of for example extra heavy oil (conventional based), the yellow stars represent the energy input values of for example oil sands (unconventional based).
*** Important notion: these energy inputs represent only the production without any downstream processes.**



The assumption that conventional production trends can also be applied to unconventional production is debatable and will be elaborated further in the discussion. The world region trends were taken, since it is uncertain whether regions that are efficient in producing conventional resources will per se be efficient with producing unconventional resources, and vice versa. Moreover, it is likely that if more regions start producing unconventional resources, they will adopt technology from the already producing region. Additionally it is assumed that more learning effects and efficiency measures for technology will cross over within regions in the future, keeping trends in energy inputs roughly the same.

3.4. TIMER model

The TIMER model was modified to incorporate the indirect energy inputs for conventional and unconventional fossil fuels. First of all, a brief overview of modifications in the TIMER model is given, with an additional explanation of the applied input/ output energy approach [Blok, 2007]. After the modifications, a description is given for the different scenarios that were analyzed, as well as the various carbon tax schemes that were considered.

3.4.1. Modifications of the TIMER model

The modifications were based on combining the direct demand for coal, oil, gas and electricity with the indirect energy needs of fossil fuel production processes. This was already present in the TIMER model through two basic mechanisms:

1) the multiplication of the demand for energy carriers with a certain fraction of indirect energy; and
2) the addition of the net transformation occurring per region per year to the demand for energy carriers.

The fraction of indirect energy demand was determined through taking the upstream losses of each energy carrier occurring in all production processes and transformation and dividing that by the intermediate output. Simply put, when regarding Table 3.5 (a simplified Table 3.3 of section 3.1), the energy losses were divided by the subtotal to get the energy fraction needed to produce 1 unit (see calculation below).

$$-\frac{-68.80}{3467.34} = 0.0198$$

If the subtotal is multiplied with the fraction plus 1, you get the original total direct plus indirect energy demand for coal. The net transformation is added to the total to get the original TPES corrected for the statistical differences.

$$3467.34 * 1.0198 + 82.53 = 3618.97$$

Table 3.5. World energy balance 2011: simplified partial version [IEA, 2014].

World energy balance 2011 (in million tonnes of oil equivalent)	
Supply and consumption	Coal & coal products
TPES	**3781.19**
Statistical differences	-162.22
Corrected TPES	**3618.97**
Transformation losses fossil fuel production	-82.53
Energy losses fossil fuel production	-68.80
Subtotal	**3467.34**
Electricity plants, CHP plants, heat plants, etc.	---
TFC	---

Although this method takes in account all of the energy flows correctly, the energy flows are not modeled interdependently. Transformations occurring in energy carrier X due to a demand change in energy carrier Y were not being incorporated in the current mechanisms. In case of historical energy data all of these changes were already accounted for, but for future projection this should be modeled dynamically. Moreover, the original model had no accounted transformation between energy carriers anymore in the years after 2005, as it assumed these cross-overs were negligible and were incorporated in the fractions of indirect energy. This will possibly lead to discrepancies with the updated model (also see section 4.3).

The assessed energy input values of section 3.3 formed the basis of the indirect energy calculation. These were put in a matrix representing the intermediate deliveries of each of the energy carriers, as showed in Equation 13. The exact values for each of the inputs depended on the state of production of that energy carrier: they are regionally dependent and depletion category dependent, for which a linear interpolation between categories was incorporated. An aspect of the TIMER model is that conventional resources can be produced simultaneously with unconventional resources[11]. To calculate what the energy inputs are at each time step, a weighted average was calculated based on conventional share and unconventional share, and on conventional active category and unconventional active category. Furthermore, the coal, oil and gas for electricity were calculated as the total amount of fuels needed for total electricity supply, divided by the total electricity supply[12].

$$\begin{array}{cc} & \underline{Demanding\ EC} \\ Supplying\ EC & \begin{bmatrix} Coal\ for\ Coal & Coal\ for\ Oil & Coal\ for\ Gas & Coal\ for\ Elec. \\ Oil\ for\ Coal & Oil\ for\ Oil & Oil\ for\ Gas & Oil\ for\ Elec. \\ Gas\ for\ Coal & Gas\ for\ Oil & Gas\ for\ Gas & Gas\ for\ Elec. \\ Elec.\ for\ Coal & Elec.\ for\ Oil & Elec.\ for\ Gas & Elec.\ for\ Elec. \end{bmatrix} \end{array} \qquad (13)$$

The oil demand for coal is added to the total oil demand. However, this oil demand would induce demand for other energy carriers, which on their turn would induce more demand. To incorporate this approach to calculate multiple orders, the Leontief Input/Output method was used [Leontief, 1986; Blok, 2007].

3.4.2. Input/ output approach

The Input/ output method by Leontief describes the total amount of deliveries induced in the economy, based on intermediate deliveries between sectors, on a monetary basis [Leontief, 1986].

[11] For coal this means hard coal and brown coal simultaneously, defined as conventional coal and unconventional coal respectively. This was done for modeling reasons [Stehfest et al., 2014].

[12] In the model, conversion losses for electricity are calculated separately. The indirect energy demand for these electricity fuels is corrected afterwards for the direct energy demand for these fuels.

The direct deliveries are categorized as the 0th order demand, the first round of deliveries induced by the direct deliveries are categorized as the 1st order demand, the second round as 2nd order demand etc. If direct energy demand is 1, indirect energy demand is depicted as X. If X would be the only energy carrier needed for producing X, the formula for total energy demand (to the nth order) becomes:

$$Total\ Energy\ Demand = 1 + x + x^2 + \ x^3 + \ x^4 \ldots + \ x^n \tag{14}$$

This is more easily written as:

$$1 + x + x^2 \ldots + \ x^n = \frac{1}{1 - x} \tag{15}$$

The method of calculation is however very dependent on the state of economy on a certain point in time [Blok, 2007]. The combination of the dynamic model (including different regions, depletion mechanisms and fossil resource category dependence) with the Input/ output total demand calculation was able to project the amount of indirect energy demand in the future.

The method used was by first taking the matrix of seen in Equation 13 (called matrix A), and calculating the total deliveries matrix P using Equation 16.

$$P = (I - A)^{-1} \tag{16}$$

In which Identity matrix I is given as:

$$I = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix} \tag{17}$$

By multiplying total deliveries matrix P with the direct energy demand matrix, the total direct and indirect energy demand of each energy carrier was calculated. These indirect coal, oil, gas and electricity demands were added to the direct energy demand in the model. For modeling reasons, the indirect energy demand calculation was based on the 6th order energy demand, although the theoretical approach stays the same. The difference between the 6th order and the 7th order is negligible, so the approach seems justified.

As seen in section 3.1, the energy inputs calculated for the production of each of the conventional energy carriers by means of the IEA extended balances have already incorporated the total of intermediate deliveries. The energy inputs for unconventional production are based on individual processes though: they have not incorporated upstream energy deliveries and cannot be directly compared to the conventional energy inputs. These conventional energy inputs were therefore recalculated to their original state of energy inputs per unit with a reverse Input/Output method

These conventional energy inputs were dependent on the state of the energy system: if direct gas inputs for producing oil were twice as high, higher gas demand would induce higher demand for other energy carriers etc. This will be illustrated in Example box 2 below.

Example box 2: the importance of higher order intermediate deliveries.

Only imposing the 1st order energy demand above the direct 0th energy demand for energy carriers [Blok, 2007], would lead to a small error if energy inputs are small and a larger error if energy inputs for the production of fossil fuels are high. An example will illustrate the case, as seen in Table 3.6. The error that occurs if only small energy inputs are present is rather small with 1% in this example. You could say that current fossil fuel production has rather small energy inputs. If fossil fuel production however requires higher energy inputs (for example with unconventional fossil fuels gaining larger market shares), the error that occurs is 20% in this example. Although this seems very logical and simple, this may be a major shortcoming in models that due to simplicity reasons merely add the 1st order energy demand to the direct energy demand.

Table 3.6. Example illustration of errors occurring in total energy demand in a small energy inputs case and a large energy inputs case.

	Small energy inputs case		Large energy inputs case	
	Direct demand : 1 J Energy input fraction : 10% J		Direct demand : 1 J Energy input fraction : 50%	
	Imposing 1st order demand	Imposing all order demand	Imposing 1st order demand	Imposing all order demand
	$1\,J + 1\,J * 10\% = 1.10\,J$	$\frac{1\,J}{(1-10\%)} = 1.1111\,J$	$1\,J + 1\,J * 50\% = 1.50\,J$	$\frac{1\,J}{(1-50\%)} = 2\,J$
	Difference calculation (%)			
	$\frac{(1.111\,J - 1.10\,J)}{1.111\,J} = 1.0\%$		$\frac{(2\,J - 1.50\,J)}{2\,J} = 25.0\%$	

Input fractions of 50% in total are possible in case of for example shale oil, as will be shown in section 4.3, although the total is subdivided over the four energy carriers. The example of Table 3.6 can become reality in case shale oil is again supplied by shale oil, and other unconventional sources are also requiring high energy inputs. For modeling purposes, if the order approach would be limited to a 2nd order approach, the error occurring would still be $2 - (1 + 0.5^1 + 0.5^2)/2 = 12.5\%$.

3.4.3. Internal vs external energy inputs

An important aspect to take in account is the difference between internal and external energy inputs. External energy inputs are energy carriers that are being imported from outside the resource production system but consumed within, for example refined diesel or electricity input. Internal energy inputs are energy carriers that are produced and consumed within the resource production system, for example oil sands or shale gas input. It would not be correct to calculate higher order deliveries or downstream energy inputs for them, since they are already consumed within the system. The modifications will take in account these differences in energy input type characteristics.

3.4.4. Scenario analyses

In order to analyze the effects of a more detailed representation of upstream energy losses on energy use and emissions, several scenarios were considered. First of all baseline scenarios were considered in order to compare the results of the model with modifications with the original model. A baseline scenario can be seen as a business as usual scenario, in which energy demand and corresponding emissions continue on projected trends, in case no exogenously induced changes occur. Regarding mitigation strategies, this means that there would not be any measure or policy in effect. To see what the effects were, the baseline energy and CO_2 emission trends of the original model and of the model with modifications were compared and analyzed.

Secondly, several scenarios with mitigation strategies were considered, as explained in the section Mitigation strategies below. As the modifications allowed for different carbon taxing schemes, the scenarios with different mitigation strategies in the modified model were compared to the original model with a standard mitigation strategy.

Several variables under review for the baseline scenario analysis were for example:

- the annual global primary energy use per energy carrier;
- resource production, and in particular oil production;
- fuel price development;
- development of energy requirement for energy per energy carrier; and
- annual global CO_2 emissions.

Within the mitigation scenario analysis the same variables as given above were considered, supplemented with the annual global CO_2 emissions per energy carrier.

3.4.5. Mitigation strategies

To simulate mitigation strategies, several carbon tax schemes were considered. Besides the direct energy involved in fossil fuels, this research gives insight in the upstream losses that could be incorporated in the carbon tax of particular fuels as well. This would account for the upstream life cycle of the product: adding an appropriate carbon tax creates a monetary incentive for the model to increasingly select cleaner produced fuels. Whether these upstream emissions can be sequestrated, depends on the means of production and processing. Mostly they are being emitted at the mining location or bore well, where capturing the fugitive emissions is not customary.

To account for the different possible mitigation strategies, two carbon tax schemes considered:

1. A carbon tax that only incorporates direct energy emissions, based on the carbon content of the fuel. These taxes run from $ 0.- to $ 1,500.- per tonne CO_2 equivalent linearly in timeframe 2015 to 2100 and are the same for all regions. This tax addition over the carbon content is the current way of incorporating the carbon tax in the TIMER model[13].
2. A carbon tax incorporating direct and indirect emissions. For each fuel at each moment in time in the model, an upstream emission factor is calculated by distilling the energy inputs needed for producing that fuel. These emissions are multiplied with the corresponding emission factors of the fuels of the producing countries[14] and summed to make up the total upstream CO_2 emissions per fuel, being regionally dependent. The direct and indirect carbon tax (of the importing region) is imposed on each of the fuels after the fuels have been traded. This taxing scheme would typically be executed if only certain regions would impose a carbon tax, i.e. the European Union or OECD countries, with the remark that these regions would possibly also incorporate the higher carbon tax into the initial selection of the fuels, although not accounted for in this taxing scheme. These taxes run from $ 0.- to $ 1,500.- per tonne CO_2 equivalent linearly in the timeframe 2015 to 2100.

A possibility for CO_2 sequestration in the model in the mitigation scenarios is Carbon Capture and Storage (CCS) [GEA, 2012; Koelbl et al., 2013]. In this concept the CO_2 emitted through the combustion of fossil fuels is being captured, concentrated and transported to a central hub where the CO_2 can be stored underground. This would typically occur with electricity generation, as you would need a centralized area where a lot of CO_2 can be captured to keep the technology economically viable. Among possible storages are for example aquifers and depleted fossil resource reservoirs, but also coalbed methane reservoirs are promising storage possibilities. For the carbon tax, this would mean that the direct emissions associated with the fuels (based on the carbon content) can be sequestrated, and the imposed direct tax is avoided.

For CCS within electricity these taxes are only partly imposed: the direct emissions can be sequestrated, while indirect upstream emissions can not be sequestrated. This means that even if CCS is combined with electricity production, the prices of this produced electricity comprise a part of the carbon tax. This will be tested however in the Sensitivity analysis.

[13] Although it was only possible to tax direct emissions in the original TIMER setup, taxing schemes can be different from this linear $ 0.- to $ 1,500.- carbon tax per tonne of CO_2 equivalent.
[14] The emission factor of electricity can be low or negative due to a possible majority of renewables in the electricity mix.

4. Results

This chapter begins with the static analyses of energy inputs for conventional and unconventional production methods, after which a comparison is made with energy inputs found in other literature. In section 4.1.1 the historical trends of fossil resource production and processing are discussed. In section 4.3 the effects of incorporating these newly assessed figures in the TIMER model are analyzed for several variables, comprising primary energy (per technology and in total), trends in upstream energy per technology, CO_2 emissions and general trends regarding upstream energy consumption. From these variables and trends, the effects of climate policy can be determined in different mitigation strategy scenarios.

4.1. Energy analysis of conventional production methods and processes

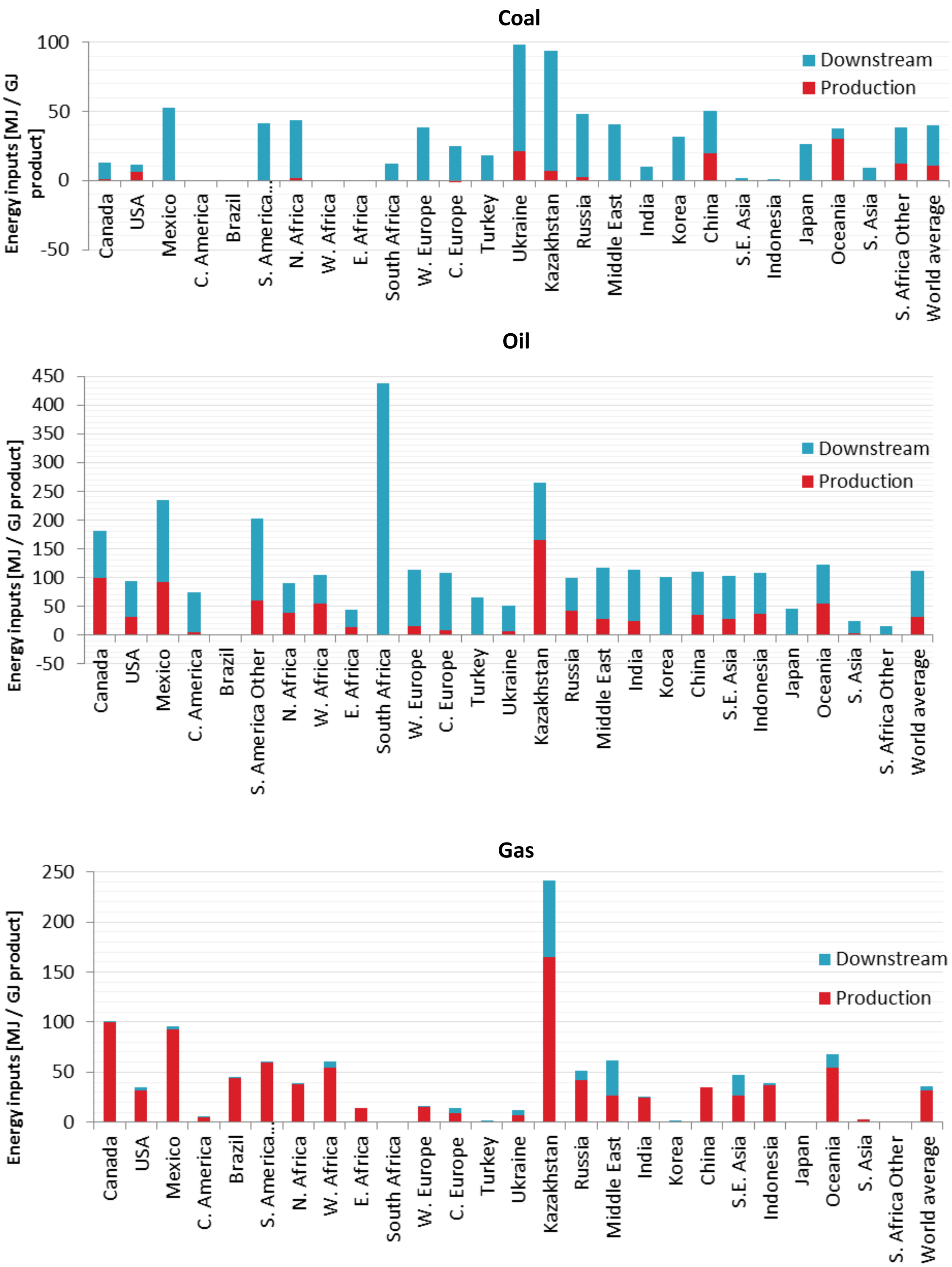
The data in the IEA extended energy balances [IEA, 2014] has been aggregated and allocated in section 3.1 of the Methods. The results are shown in Figure 4.1 (see next page). This data for the 27 TIMER regions presents an overview of the 2011 energy inputs for production and processing of coal, conventional oil and conventional gas. These figures however have changed over time as will be seen in the trend analysis in section 4.1.1 below. First, the 2011 status quo will be described.

As is shown in Figure 4.1, coal in general has the lowest energy inputs of the three energy products. Production energy inputs result from coal mining; downstream energy use occurs in coke ovens, patent fuel fabrication and BKB fabrication. The world average energy input for coal production is 11 MJ /$GJ_{product}$; for downstream processing global average energy input is 29 MJ /$GJ_{product}$. The regions Ukraine, China and Oceania have the highest energy inputs during coal production. For coal downstream processing, the highest energy inputs occur in Mexico, Ukraine, Kazakhstan and Russia, which proves the energy consumption in coal processing is still high in the former Soviet states.

Oil production energy inputs are generally higher than coal production inputs. Downstream processes as liquefaction, refining and petro-chemistry are quite energy intensive and therefore also require a substantial amount of energy inputs. The world average energy input for production of oil is 38 MJ /$GJ_{product}$. For downstream processing the global average energy input is 79 MJ /$GJ_{product}$. As can be seen in Figure 4.1, oil production energy inputs are quite high in Canada, Mexico, Kazakhstan and Oceania. Canadian oil energy inputs are higher than the world average, which indicates that stated separation of conventional and unconventional data by the IEA is not entirely performed.[15].

[15] In the model, this was overcome by correcting Canadian conventional energy inputs for the unconventional production by taking the U.S. average for conventional oil production.

Figure 4.1. Energy inputs for coal, conventional oil and conventional gas in the year 2011, given for production and downstream processing for the 27 TIMER regions (see Annex A for the definition of the TIMER regions) [IEA, 2014]. Due to unavailability of adequate data, Central America, Brazil, East Africa and West Africa were left out of the coal graph. The IEA data also lacked appropriate information for oil production and processing for Brazil. Electricity input has been converted to primary energy with an average conversion rate of 36%.



The higher energy inputs for Mexico and Oceania can be explained by their large share of off-shore production in the oil production mix. Kazakhstan has high energy requirements for oil production, an observation also seen in coal processing in the coal graph of Figure 4.1. Downstream processing energy inputs are high for Mexico, South America and South Africa. The higher South American downstream processing energy inputs can be explained by the Venezuelan extra heavy oil needing extra upgrading and refining efforts. South Africa's higher energy requirement can be explained by large-scale coal-liquefaction to produce liquid fuels[16].

Conventional gas production energy inputs per produced unit are assumed to be equal to the oil production energy inputs per produced unit as a result of the method used (see section 3.1). Comparing average EROI values of oil and gas production in other literature, this assumption seems justified (see section 4.2.3). Therefore the same energy requirement is assumed within each region for both energy carriers. Downstream processes as LNG and gas works add 4 MJ /$GJ_{product}$ on average to the global figures. Energy inputs for downstream processes are fairly low, although somewhat higher inputs are needed in the Middle-East and South-East Asia, in which LNG facilities are being deployed. South-East Asia) also increasingly deploys those activities, as can be seen from the downstream energy inputs in that region in Figure 4.1. Kazakhstan's high downstream energy use is due to the high energy consumption in gas works operations.

4.1.1. Historical energy use in conventional resource production and processing

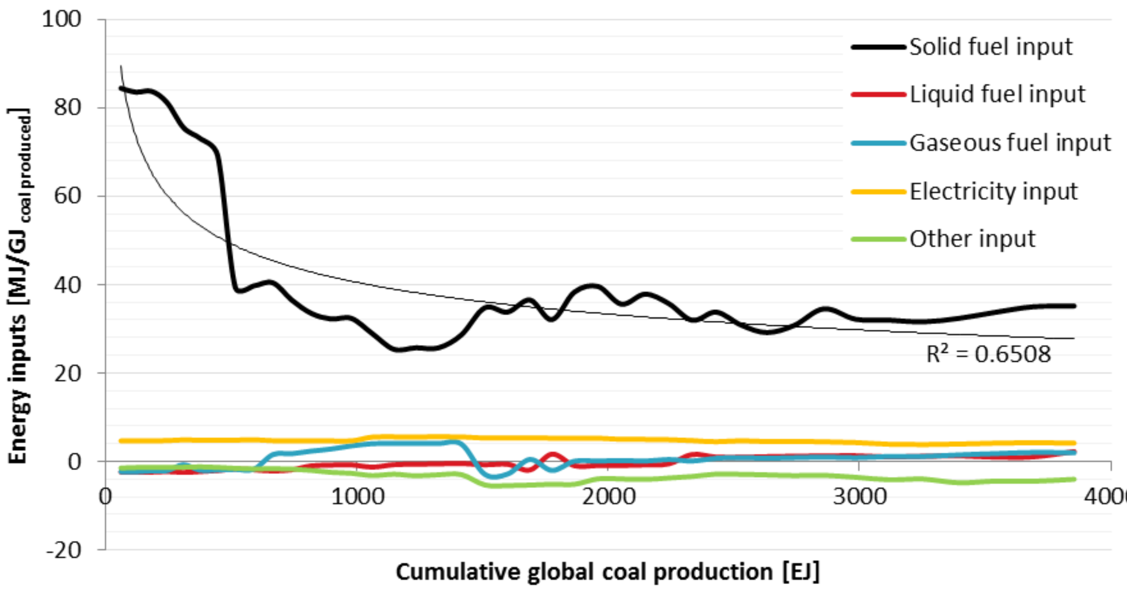
In this section the energy input trends in fossil resource production and processing are shown, from 1971 until 2011. These will be used to derive future trends in energy requirements. The energy inputs are plotted against the cumulative production of each resource since 1971, based on the assumption that energy inputs are dependent on depletion and learning by doing effects [Dale, 2010]. Actual cumulative production of each region was higher, but the IEA started monitoring global figures in 1971.

Coal production and processing

Figure 4.2 shows that solid fuel makes up the most important energy input for coal production and processing. Solid fuel energy requirements historically decreased with a downward roughly logarithmic trend. This reduction in energy inputs can be explained by learning effects. Electricity input is also decreasing with cumulative production and there is a tendency of more other outputs being co-produced (indicated by the increasing negative trend) mainly in the form of heat. Trends for liquid and gaseous fuel inputs show a fairly constant rate.

[16] As stated earlier, the energy inputs with regard to oil production of South Africa and other regions with historical high energy use in fuel production are gradually but quickly converged to the world average.

Figure 4.2. Energy inputs for global coal production and downstream processing. The inputs are based on a global average, plotted against cumulative global coal production, starting in 1971 until 2011.



Oil production and processing

Figures 4.3 and 4.4 show energy input trends for oil production and oil downstream processing, from 1971 to 2011 based on a global average. The graphs show that gaseous fuel is the most important energy input for production, while liquid fuel is the major input for downstream oil processing. In the historical trends, downstream processing has had the upper hand. With the current trends taken in account, the energy inputs for production gain in energy input share in the total supply chain though. Gaseous fuel input in production increases considerably with cumulative oil production, while the other energy inputs are stagnating. The best fitting relation for the gaseous fuel input is a linear increasing relation starting from 1971 (at 0 EJ in the graph). If the trend would start around 1980 (corresponding with the dip to 10 $MJ/GJ_{\text{oil produced}}$ around 1300 EJ cumulative production), the linear relation would still give the best fit, although with a steeper slope. Starting the trend in 1971 therefore gives a more conservative estimate of the extrapolation. The dip was actually preceded by an odd period of oil production, as due to the 1st and 2nd oil crisis, other regions than the Middle-East had to produce oil to fulfill the global needs. This was the cause for the less efficient period of oil production.

An important notice is that regions as Canada and Venezuela, known for their unconventional oil production, make up for 11% of worldwide oil production in 2011 and around 10% of total cumulative oil production from 1970 to 2011. Besides, unconventional oil production is only a small share in the indigenous oil production in those regions, with unconventional oil only having gained a significant market share of 3.5% in the last couple of years [GEA, 2012; Mohr & Evans, 2012] (also see Table 2.1).

These regions therefore do not influence the global average so much to be able to explain the whole increasing trend of gaseous fuel requirements.

Another important trend to notice is the slight upward slope of electricity input. Electricity needs to be converted and will induce more direct and indirect demand, when generated with fossil fuels.

Figure 4.3. Energy inputs for global oil production. The inputs are based on a global average, plotted against cumulative global oil production, starting in 1971 until 2011.

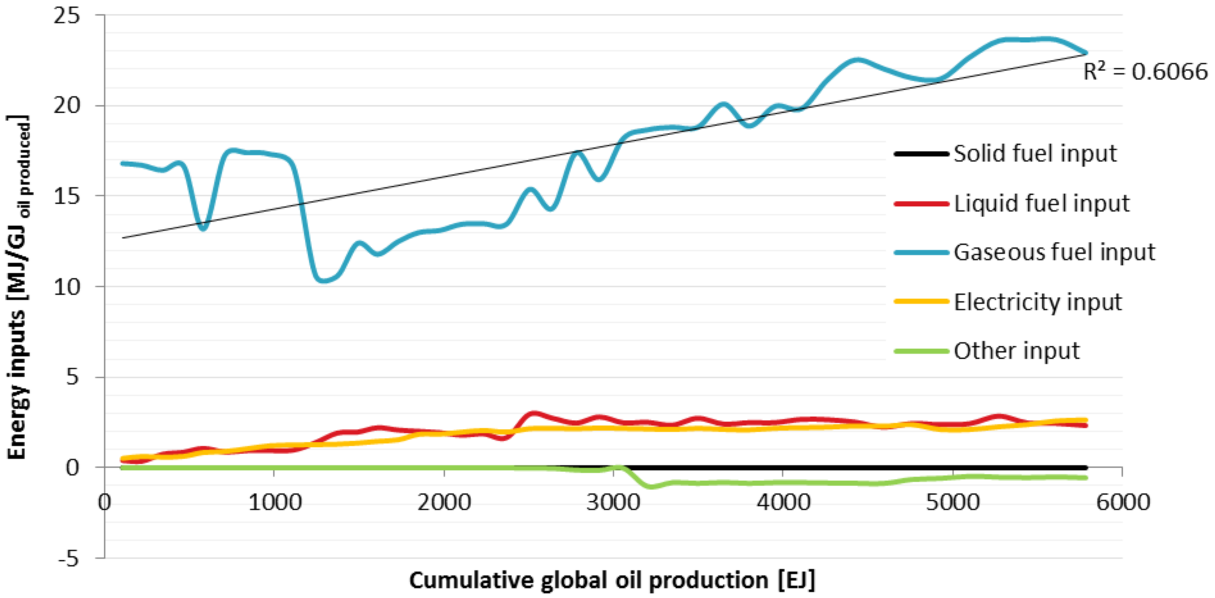
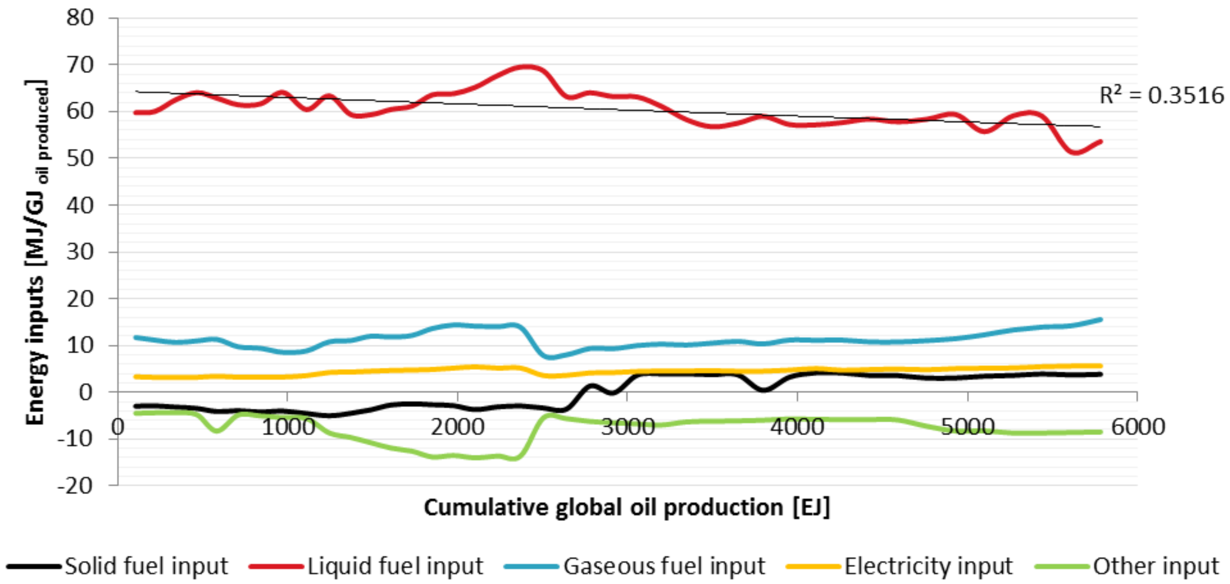


Figure 4.4. Energy inputs for global oil downstream processing. The inputs are based on a global average, plotted against cumulative global oil production, starting in 1971 until 2011.

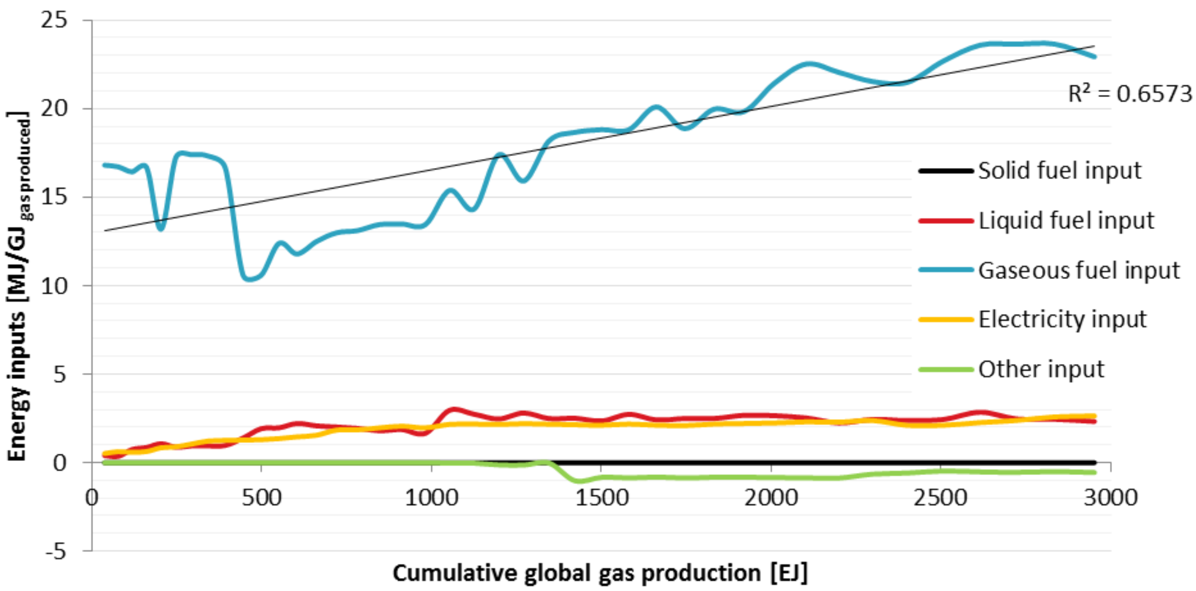


In downstream oil processes (e.g. refining, liquefaction) there is a slightly downward trend in liquid fuel inputs per produced oil product, although the trend relation indicates a stagnating relation. Gaseous fuel inputs have gone down after around 2,500 EJ cumulative production since 1970 and are increasing in the last couple of years. Gas inputs show a resemblance to the other inputs, mainly consisting of heat production. Electricity inputs remain steady.

Gas production and processing

The same as for oil production, gas inputs make up a substantial share in the total input for gas production. Figure 4.5 shows an upward trend in gaseous fuel input, while the other energy inputs are stagnating. Starting the trend in 1971 (at 0 EJ in the graph) gives a more conservative estimate than starting in 1980 (around 1300 EJ). For downstream gas processes, a global trend was not possible to give, as inputs were fluctuating heavily. Because activities of LNG or gas works operations are very region specific, these are accounted for within the regions. Regarding distribution losses for gas, the global average will be added to each region to account for downstream gas processes, which will be kept constant throughout the years as it is not certain whether these figures will go up or down in the future.

Figure 4.5. Energy inputs for global gas production. The inputs are based on a global average, plotted against cumulative global gas production, starting in 1971 until 2011.



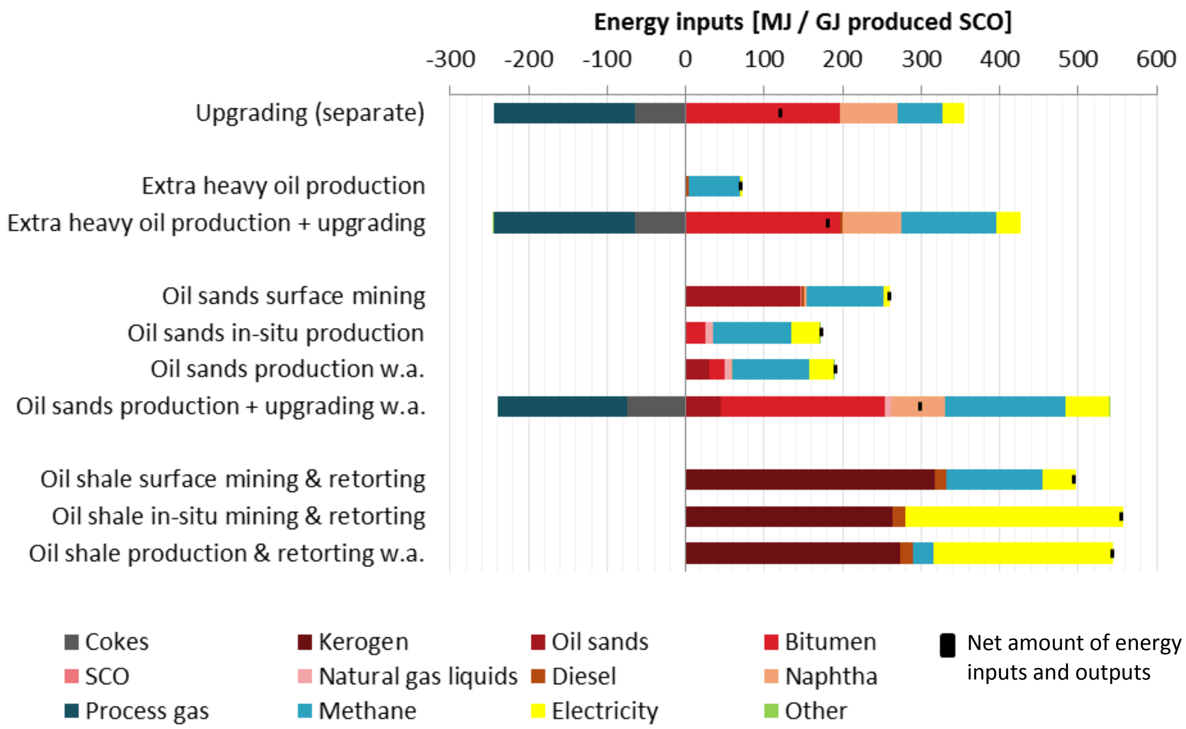
4.2. Energy analysis unconventional production methods

This section describes the analysis of energy requirements for unconventional fossil fuel production methods. The production methods for unconventional oil are given on an in-situ occurrence-to-Synthetic Crude Oil (SCO) ratio basis, as described in section 3.2. The production methods for unconventional gas are given on an in-situ occurrence-to-extracted natural gas basis. The inputs are therefore also scaled on those two products: oil inputs on a MJ_{fuel} / GJ_{SCO} basis; gas inputs on MJ_{fuel} / GJ_{SCO} basis. The assessment of energy inputs for both unconventional oil and unconventional gas types, combined with a comparison with conventional resource energy inputs and existing literature, is then used to determine likely future energy requirements in fossil fuel production.

4.2.1. Unconventional oil production methods

The overview of the energy profiles for unconventional oil production and upgrading is given in Figure 4.6. As can be seen from the figure, extra heavy oil production has the lowest unconventional energy inputs, although upgrading adds a substantial amount to the energy profile.

Figure 4.6. Energy inputs for the production of different unconventional oil types. The negative amounts represent co-produced outputs. The black dots indicate the net amount of energy inputs per process. Electricity input has been converted to primary energy with an average conversion rate of 36%.



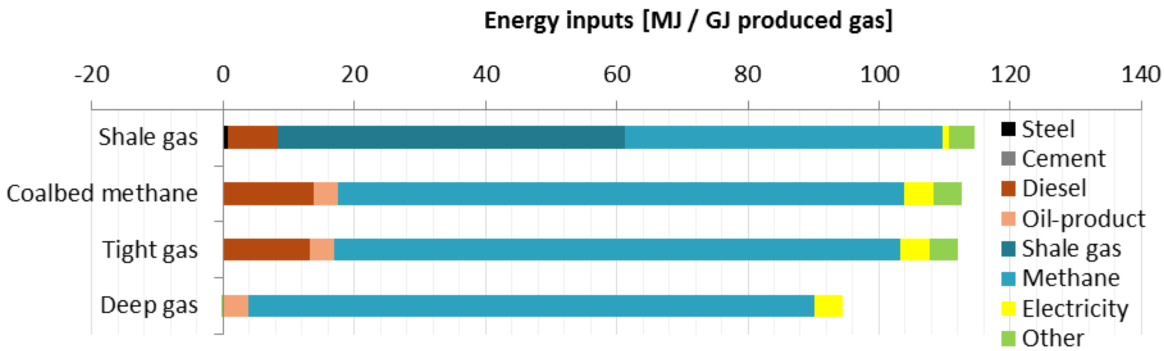
Oil sands surface mining requires more energy than in-situ production. This is mainly because surface mining relies on currently deployed methods as described in the statistical data from the Alberta Energy Regulator [AER, 2013]. In-situ production is also likely to gain a large market share. However, the surface mining method requires oil sands as an energy input, being partly self-sufficient, where in-situ methods require less bitumen input. The weighted average (w.a.) is based on the fact that 20% of the estimated resources can be produced with surface mining, the other 80% being deeper deposits requiring in-situ methods (see Section 2.1).

The energy use for upgrading differs slightly for extra heavy oil and oil sands. This is because heavy oil upgrading makes use of the average of the three types of upgraders as assessed in section 3.2 [AER, 2013], while the figure of oil sands is also based on the average upgrading energy requirement of integrated oil sands production and upgrading. The upgrading requires considerable inputs (although being mostly self-sufficient with bitumen), but co-produces petroleum cokes and process gas, a form of gas comparable to refinery gas. The co-production of cokes is a subject of debate though, as the cokes produced in Canada were stockpiled initially, rather than used (see Discussion). There are some business cases emerging for the cokes though [New York Times, 2013; Murthy et al., 2014]. Here it is assumed that cokes are part of the upgrading energy profile.

Oil shale mining requires higher energy inputs than the other two types. Especially the retorting adds to the energy profile. The process requires mostly kerogen[17] and methane input to extract and upgrade other kerogen into Synthetic Crude Oil (SCO). The in-situ mining method however requires electrical heating and the freeze-wall, adding to the electricity input (see section 2.2). This electricity input partly offsets the required methane input for retorting, with the in-situ method also producing SCO. Due to the large amount of kerogen input, the production method is self-sufficient for a substantial part.

4.2.2. Unconventional gas production methods

Figure 4.7. Energy inputs for unconventional gas production, based on a global average. Electricity input has been converted to primary energy with an average conversion rate of 36%. Other inputs mainly consist of embodied energy in chemicals for waste water treatment and hydraulic fracturing.



The overview of the energy profiles for unconventional gas production is shown in Figure 4.7. Of the unconventional gas types, shale gas requires most of the energy inputs per product. Tight gas and coalbed methane are based on trend extrapolations of energy inputs for unconventional gas and

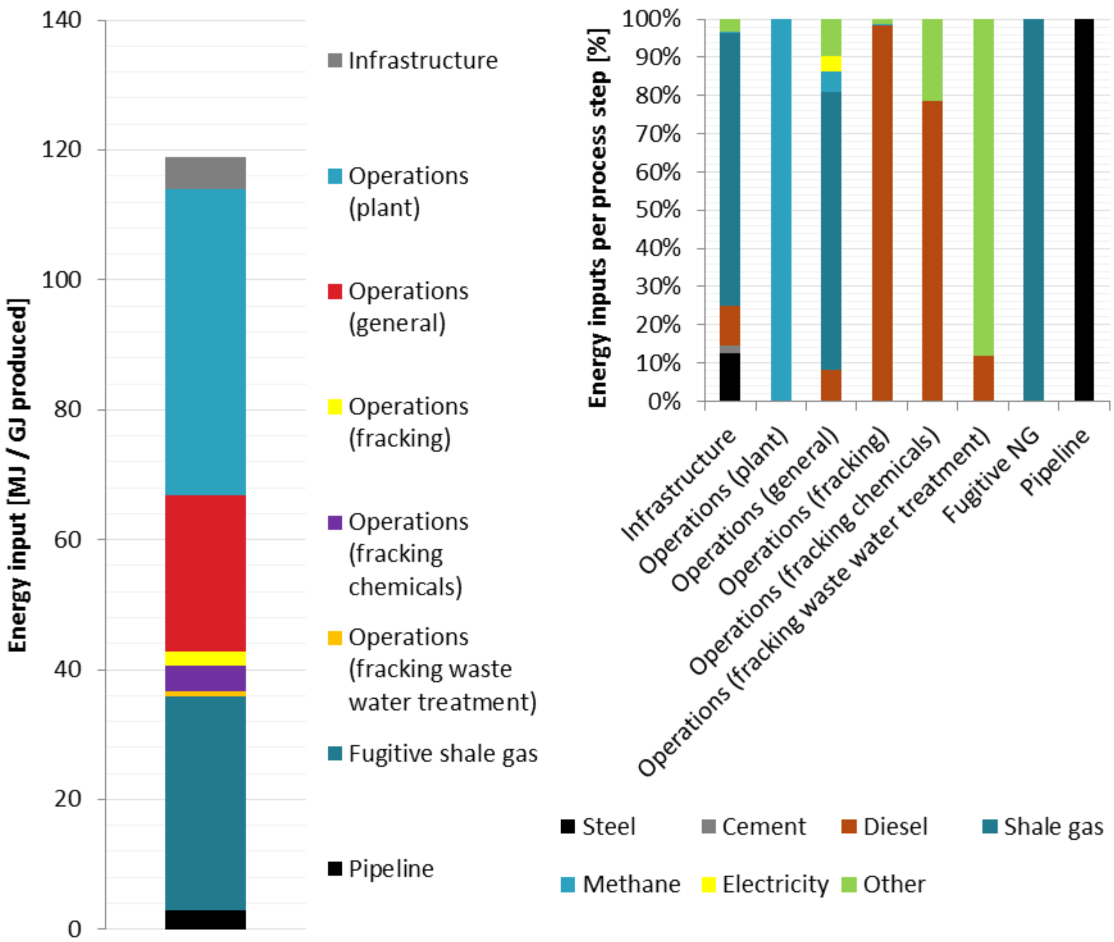
[17] Kerogen is basic organic matter from which shale oil is produced, see section 2.2.

hydraulic fracturing energy requirements (see section 3.2). The diesel and other energy requirements are needed for the hydraulic fracturing. The deep gas energy profile is based on the trend extrapolation of energy inputs for conventional gas production. Tight gas and deep gas deposits require lower energy inputs than shale gas, which is also the reason that these resources are increasingly categorized as conventional gas types [GEA, 2012].

The energy requirements for gas production are all in the same order of magnitude as shale gas. The plausibility of the energy profiles of the three non-shale gas resources can be debated, however no sufficient data on production of these three resources was available.

As can be seen from Figure 4.7, shale gas and external methane input make up for most of the energy inputs in shale gas production. This is mainly because of general operation energy requirements like drilling and infrastructural requirements (also see Figure 4.8).

Figure 4.8. Production steps and energy inputs in shale gas production. The left graph shows how the different production steps add up. The right graph indicates the energy inputs in each production step as a percentage of the total in that production step. General operations comprise drilling, gas compression and gas processing. Electricity input has been converted to primary energy with an average conversion rate of 36%. The energy input Other mainly consists of chemicals for waste water treatment of the hydraulic fracturing water and the chemicals needed for the sustainment of open pore space in the gas reservoir during hydraulic fracturing.



Moreover, the fugitive emissions are added to the total energy profile. This might seem a bit inconsistent as in the other gas types no fugitives were assumed. These fugitives are however assumed to already be in the figures of conventional gas production, on which the extrapolated energy inputs of the three non-shale gas types were based. Fugitives however add to the energy profile as is shown in Figure 4.8, and will therefore be a point of discussion in the Sensitivity analysis.

Furthermore Figure 4.8 shows that the production steps around hydraulic fracturing do not require much energy: only 5.8% of the total energy needed for production is consumed during fracturing. This energy profile does not incorporate other impacts of the involved fracturing chemicals and water use. Another aspect seen from the figure is the low proportion of energy embodied in materials in the total energy profile. The energy for pipelines comprises totally of energy embodied in steel, which is 2.3% of the total energy profile. This amount is very uncertain though, as it can not be exactly determined how much of the existing pipeline infrastructure can be allocated to the production of a shale gas unit. Other material inputs, for example in the infrastructural requirements of steel and cement for the bore wells are 0.5% and 0.1% of the total energy requirement for shale gas production. The assumption to leave these inputs out of the unconventional resource energy profiles used for the TIMER model therefore seems justified.

4.2.3. EROI analysis

Figures 4.9 and 4.10 show the energy inputs for fossil resource production and processing, for total energy inputs (Figure 4.9) and only external energy inputs (4.10)[18]. In the latter case, internal inputs (e.g. oil in oil production) are ignored. This distinction is of importance, as internal energy inputs do not require the energy downstream inputs (transport, refining etc.) or indirect energy as they are used up before they reach those stages. Furthermore, the internal energy inputs are basically free energy inputs, as it will only reduce output. Examples are the difference between using crude oil or diesel in oil production and between naturally occurring coal or coal product inputs in coal production.

This aspect also influences the energetic feasibility of producing the resource, as total inputs cannot surpass total produced output, since that would result in a net energy loss. This is similar to the Energy Return on Investment (EROI) topic as discussed in the Introduction, where an EROI of less than 1 would mean a net energy loss. This notion would mean that particularly oil shale production approaches this value, as 625 MJ_{input} / GJ_{output} results in an EROI of 1.60 (1/0.625, see Figure 4.9 and the EROI Equation 1 in the Introduction). Furthermore, this static value of 625 MJ_{input} / GJ_{output} is likely

[18] The values in Figures 4.10 and 4.11 are a simple summation of all energy inputs; electricity was converted to primary energy with an efficiency if 36%.

to increase in the future, as a result of the oil production trends identified in section 4.1, resulting in even lower input to output ratios.

Figure 4.9. Total energy inputs of fossil resource production and processing.

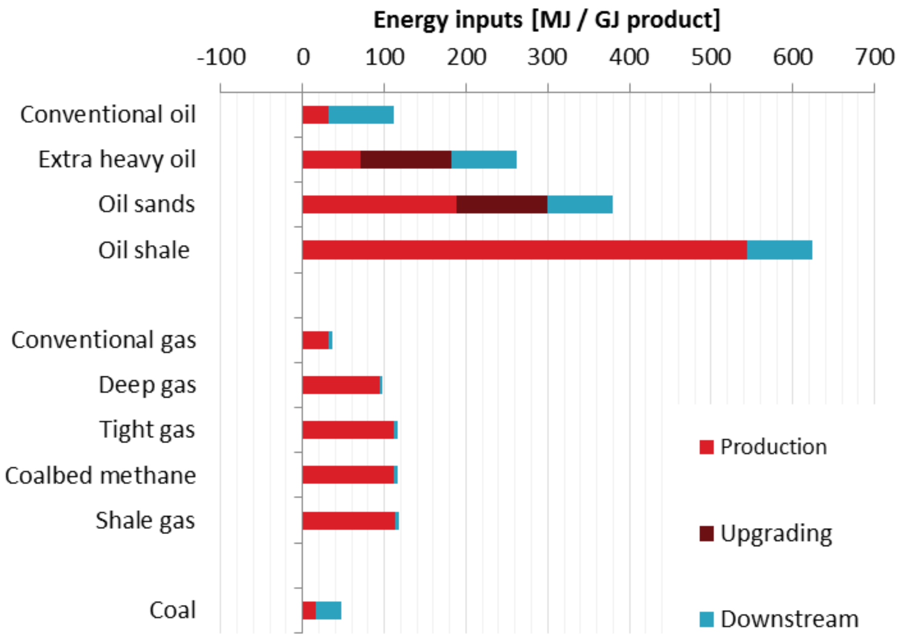
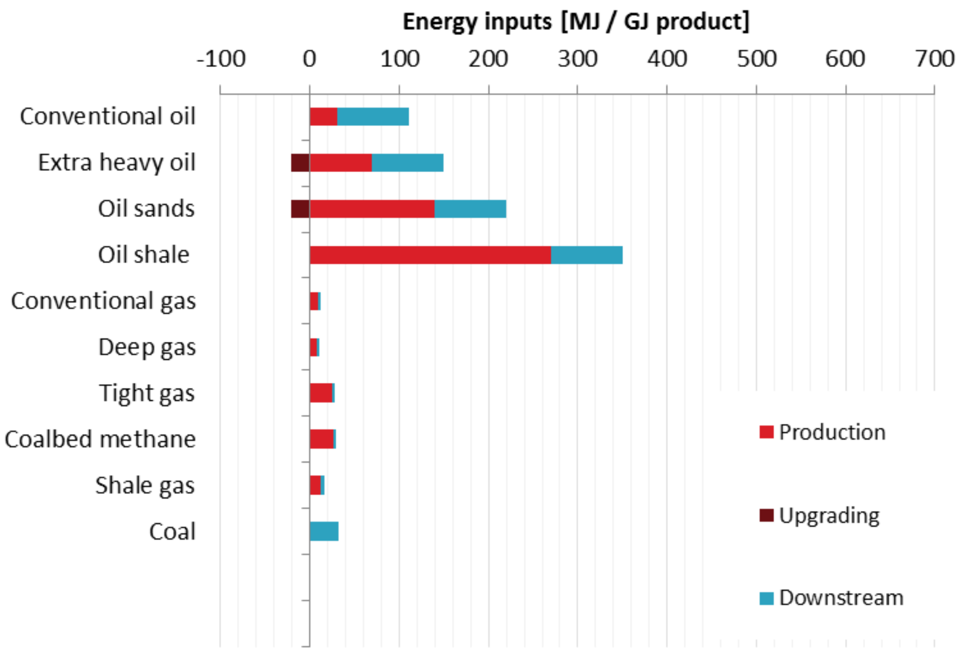


Figure 4.10. External energy inputs of fossil resource production and processing.



The external energy requirements of shale oil are much lower, with energy requirements of 350 MJ_{input} / GJ_{output} (see Figure 4.11). This value is much lower than the value in Figure 4.9, as the kerogen input, that made up 50.3% of energy inputs, was left out in this calculation. This also seems a more justified value from an reality perspective, as illustrated with an example (Example box 3).

Example box 3. Considerations regarding the internal and external energy inputs.

Oil shale present in the sub-surface has no intrinsic value initially. Only if you start producing shale oil or other energy products from it (with or without upgrading) you have a product with a calorific value that can be used for an energy function. Regarding external energy inputs: they could have been used otherwise and should be counted as an energy investment. Regarding internal energy inputs: they would have had no other function and be worthless, unless used for this activity. To put it simply, to gain 1 gold nugget you would be kind of indifferent whether to invest 5 or 10 worthless grey stones.

When regarding other aspects than purely energy there are however objections to this view. Kerogen use above ground and its corresponding CO_2 and other emissions cannot be differentiated from other energy inputs and their emissions. Other impacts on the environment and sub-surface are also not taken in account, for which aspects it could be beneficial to let the fossil resources stay untouched in the sub-surface. These matters will not be further elaborated on in this research although they should be taken in account in the general discussion on these unconventional fossil resources.

The difference between Figure 4.9 and Figure 4.10 shows that coal production is almost entirely dependent on internal energy inputs. This calculation has been done by looking the type of inputs: for example: producible coal types (anthracite, bituminous coal, lignite etc.) were categorized as internal energy inputs and left out, coal products (patent fuels, cokes etc.) and other energy carriers (diesel, gas) were categorized as external inputs. Conventional oil production mostly consists of external energy inputs as the values in Figures 4.9 and 4.10 are almost equal. The comparison of Figures 4.9 and 4.10 shows that unconventional oil types depend only partly on external energy inputs. Figure 4.10 shows a large reduction in the energy requirements for all gas types, in comparison to Figure 4.9, indicating that a large share of total energy inputs comes from internal energy sources. Most of the external energy inputs consist of hydraulic fracturing requirements for tight gas, coalbed methane and shale gas. The difference in energy requirements results from the difference in total estimated ultimate gas recovery of each gas well.

A comparison between the EROI values obtained from this research and the EROI values found in literature is given in Table 4.1. Only sources other than the ones used in this study are shown. It is important to notice that the sources mentioned in Table 4.1 were not suitable for this research, as they did not incorporate sufficient build up of how these EROI values were constructed. The EROI values in other literature give a good indication though whether values as assessed in this research are valid. A remark for the table is that most of the unconventional values in literature are based on process analyses, without taking downstream energy inputs in account. This means that on average, EROI values for this research might be slightly lower than in literature.

Table 4.1. Overview of EROI values of this study and in literature. Only external means that only external energy inputs are taken in account, also the Net External Energy Ratio [Aucott & Melillo, 2013].

Resource Type	This research	This research (only external)	Literature average	Literature range	Sources
Conventional oil	8.9	9.0	11.7	4.2 – 23	[Cleveland et al., 1984; Delucchi, 2003; Dale, 2010; Mulder et al., 2010; Murphy & Hall, 2010; Hall et al., 2010; Guilford et al., 2011; Hu et al., 2013]
Extra heavy oil	3.8	7.8	-	-	-
Oil sands	2.6	5.0	4.1	2.8 – 5.5	[Dale, 2010; Mulder et al., 2010; Murphy & Hall, 2010; Poisson & Hall, 2013; Brandt et al., 2013]
Oil shale	1.6	2.9	4.7	0.7 – 13.3	[Cleveland et al., 1984; HoR, 2005; Backer & Duff, 2007; DOE, 2007; Dale, 2010]
Conventional gas	27.6	82.0	15	7 – 23	[Cleveland et al., 1984; Dale, 2010; Murphy & Hall, 2010]
Deep gas	10.2	92.8	7.3	1.0 – 22.0	[Cleveland et al., 1984; Gately, 2007; Moerschbaecher & Day, 2011]
Tight gas	8.6	35.3	68.5	50 – 87 (only financial)	[Sell et al., 2011]
CBM	8.6	34.4	1.86	1.86 (with CO_2 storage)	[Ibarren et al., 2013]
Shale gas	8.5	64.0	-	-	-
Coal	21.3	31.8	24.7	4 – 60	[Cleveland et al., 1984; Dale, 2010; Murphy & Hall, 2010]

The EROI of conventional oil determined in this research seems to be in line with literature, as do EROI values for oil sands and coal. The value for oil shale might be somewhat lower because downstream energy inputs are taken in account. Conventional gas and deep gas might have been assessed even a bit too high, because of a more conservative estimate regarding the future trends of energy inputs for gas. CBM and tight gas' literature were based on other methods, which could explain the totally different values. There was no additional literature for shale gas and extra heavy oil, as already all the literature found was incorporated in the research.

4.3. Baseline and mitigation scenarios in the original model and the updated model

In this section, the effects of incorporating the energy profiles of the previous two sections are analyzed with the TIMER model. This will be done through baseline scenarios and mitigation scenarios, as described in section 3.4. These results will show the impact on the global energy system with corresponding emissions. First, the baseline scenario results will be discussed, followed by the mitigation scenarios. The effects shown are mainly the result of two main modifications made to the TIMER model:

1) The interconnection between the different energy carriers as a result of ERE requirements (e.g. gas demand inducing extra oil and electricity demand).
2) The updated values for upstream energy use.

In the non-modified version of the model, upstream energy demand was based on decreasing and converging 'fractions' of indirect energy added to the direct energy demand. It was assumed that the efficiency improvements would prevail over the depletion effect and that the means of production and fuel processing would eventually be the same in each world region. The upstream energy requirement developments over time can now differ per region and energy carrier, and they can increase if more energy intensive fuel types are used. Especially the incorporation of the unconventional energy use resulting from production processes could have an effect on the indirect energy demand (as seen from the higher energy requirements shown in section 4.2).

The different scenarios considered will be referred to as:

- **Scenario BaseOld: Baseline Old (original) model scenario**[19]
- **Scenario BaseNew: Baseline Updated model scenario**, in which modifications are made in the way of calculating upstream energy demand, or indirect energy demand.
- **Scenario MitigOld: Mitigation Old (original) model scenario** incorporating a global carbon tax on direct emissions only, running linearly from \$0.- to \$1,500.- per tonne of CO_2 equivalent, in a time frame from 2015 to 2100.
- **Scenario MitigNewCtaxDir: Mitigation Updated model scenario with a Carbon tax only on Direct emissions** incorporating a global carbon tax on direct emissions only, running van \$0.- to \$1,500.- per tonne of CO_2 equivalent, in a time frame from 2015 to 2100.
- **Scenario MitigNewCtaxInd: Mitigation Updated model scenario with a Carbon tax on direct and Indirect emissions** incorporating a carbon tax on direct and indirect upstream emissions, running van \$0.- to \$1,500.- per tonne of CO_2 equivalent, in a time frame from 2015 to 2100, different per region.

For more information on these scenarios please see section 3.4.

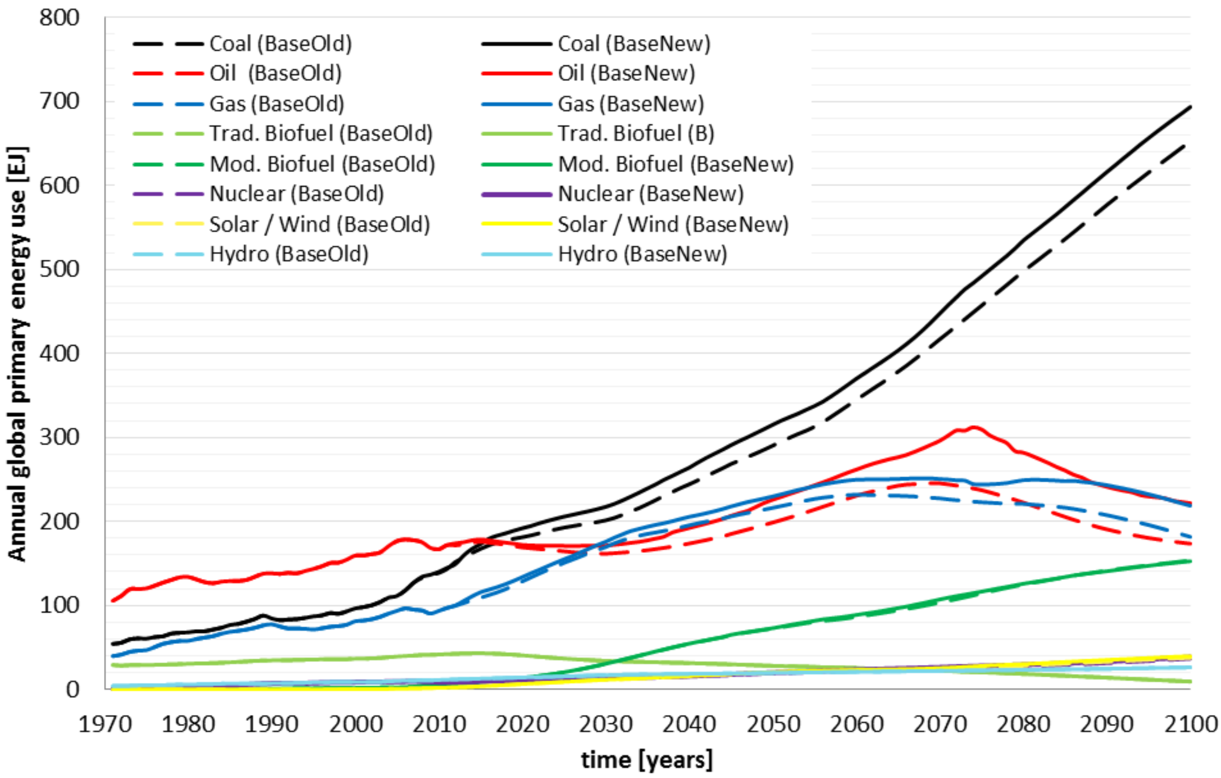
[19] OECD baseline scenario in TIMER [Stehfest et al., 2014]

4.3.1. Energy use in the baseline scenarios

In the baseline comparison differences between the original model and the model with modifications are compared on the basis of scenarios BaseOld and BaseNew. The baseline scenarios represent a business as usual kind of world in which no new policies are implemented.

Figure 4.11 shows the projected primary energy use is higher in scenario BaseNew than in scenario BaseOld. The differences between the different model setups in scenario BaseOld and BaseNew already show in 2011 (scenario BaseOld assumes a decreasing upstream energy trend, while BaseNew assumes a steady one), as primary energy use of all three fossil energy carriers increase. For coal, the energy use projections are slightly higher in scenario BaseNew compared to scenario BaseOld.This is mainly induced via the extra electricity demand resulting from the conventional and unconventional production of oil and gas. The difference in gas use between scenario BaseNew and BaseOld slowly increases over time, which is as a result of extra oil demand and extra electricity demand. Oil use in the baseline scenarios does not peak until around the year 2070 for scenario BaseOld, and the year 2075 in scenario BaseNew (also see Figure 4.12). The absolute difference in primary energy use of other energy carriers is negligible.

Figure 4.11. Projected annual global primary energy, from 1970 to 2100, for scenarios BaseOld and BaseNew.



Oil production in the baseline scenarios

A large difference can be observed in total oil use, which can be primarily explained by the fact that unconventional oil production requires a substantial amount of liquid fuel input, again primarily supplied with liquid fuel. This trend can be seen in Figure 4.12, which shows the shares of conventional and unconventional oil in global oil production.

Figure 4.12. Projected annual global conventional and unconventional oil production, from 1970 to 2100, for scenarios BaseOld and BaseNew.

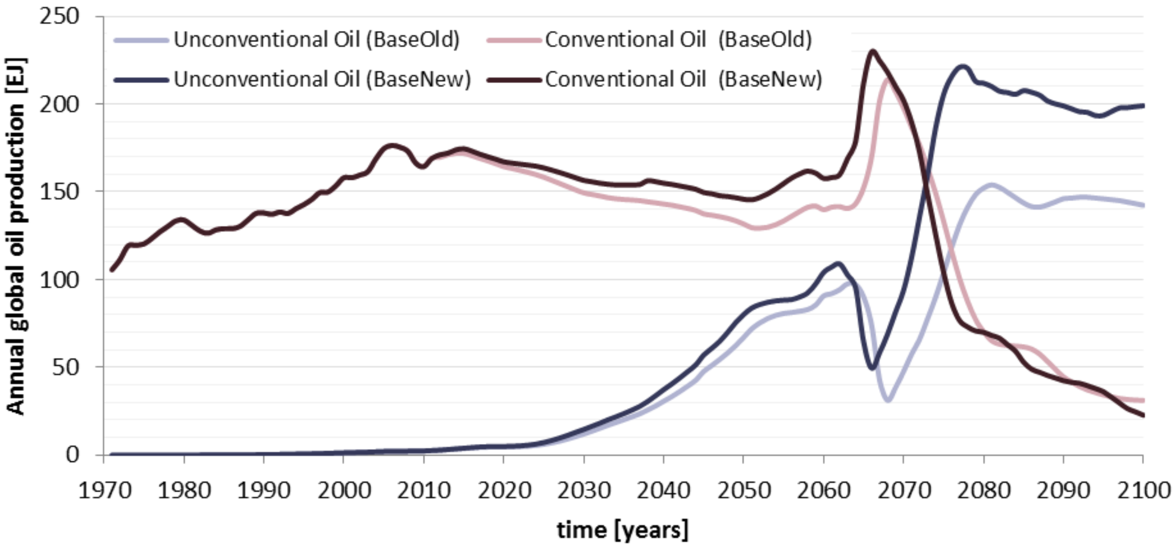
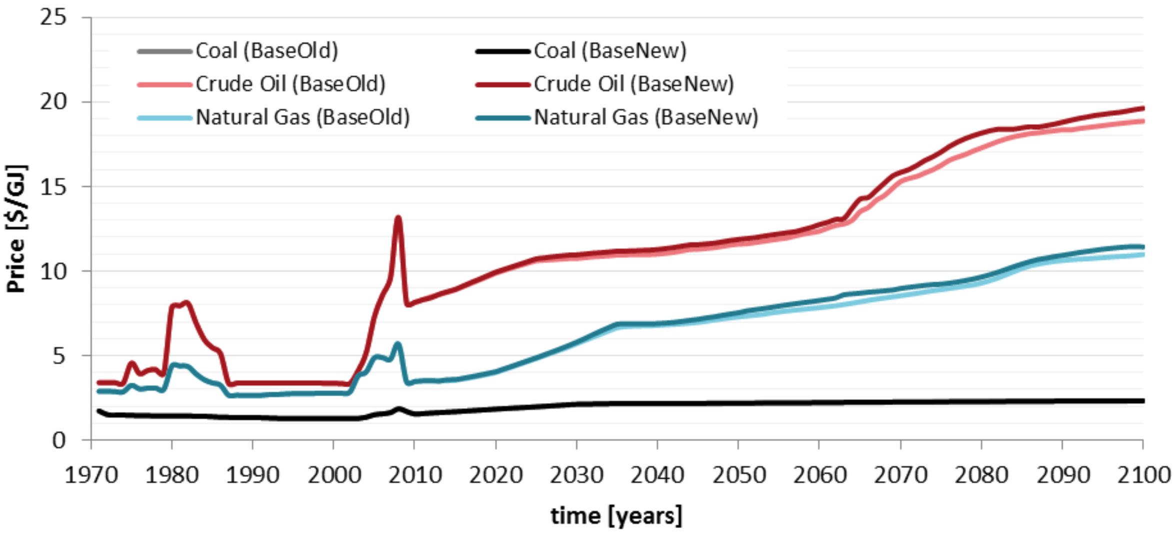


Figure 4.13. Projected global price development of coal, crude oil and natural gas, from 1970 to 2100, for scenarios BaseOld and BaseNew. The spikes seen in 2008 indicate the sudden rise in global crude oil prices as a result from the financial crisis in 2008. The gas price was linked to crude oil price developments, coal price was also slightly influenced.



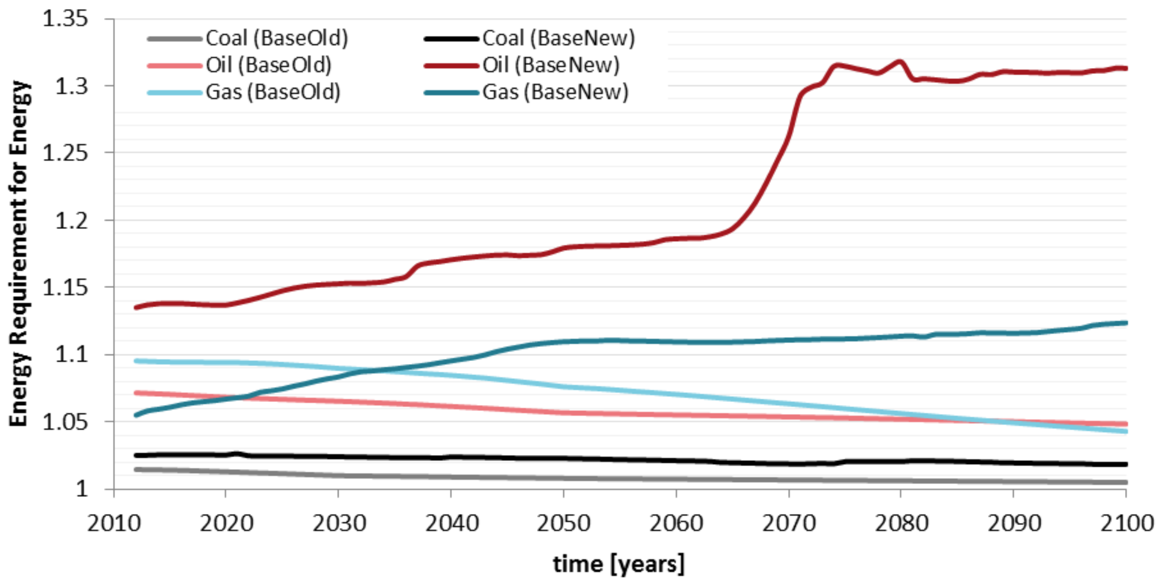
Both conventional and unconventional production have their first peak earlier in the updated model than in the original, respectively around 2060 and 2065. This is mainly the result of cost-supply curve categories that are being depleted at a faster rate. Unconventional oil production plummets after the peak in 2060 because the subsequent cost-supply curve categories are too expensive and regions are able to supply oil either themselves or from other regions at a lower cost level (see Figure 4.13 for the oil cost price development of the different baseline scenarios).

After the peak in conventional oil production around 2065, there is a large increase in unconventional oil production again, with a maximum of 150 EJ per year around 2080 in scenario BaseOld and 225 EJ per year in 2075 in scenario BaseNew. This 1.5 fold increase is mainly due to the liquid fuel use in oil production itself, a peak also seen in the total annual global primary use of oil (Figure 4.11).

Indirect energy development in the baseline scenarios

An important indicator of these changes, is the development of the global average energy requirement for energy (ERE), shown in Figure 4.14. All of the energy carrier inputs are summed: solid fuel, liquid fuel, gaseous fuel and electricity, divided by the average conversion efficiency. This is a first order ERE, as higher orders would have been influenced by EREs of other energy carriers. The ratio 1 : ERE can be seen as the ratio final energy : primary energy.

Figure 4.14. Projected global energy requirement for energy development, from 2015 to 2100, for scenarios BaseOld and BaseNew.

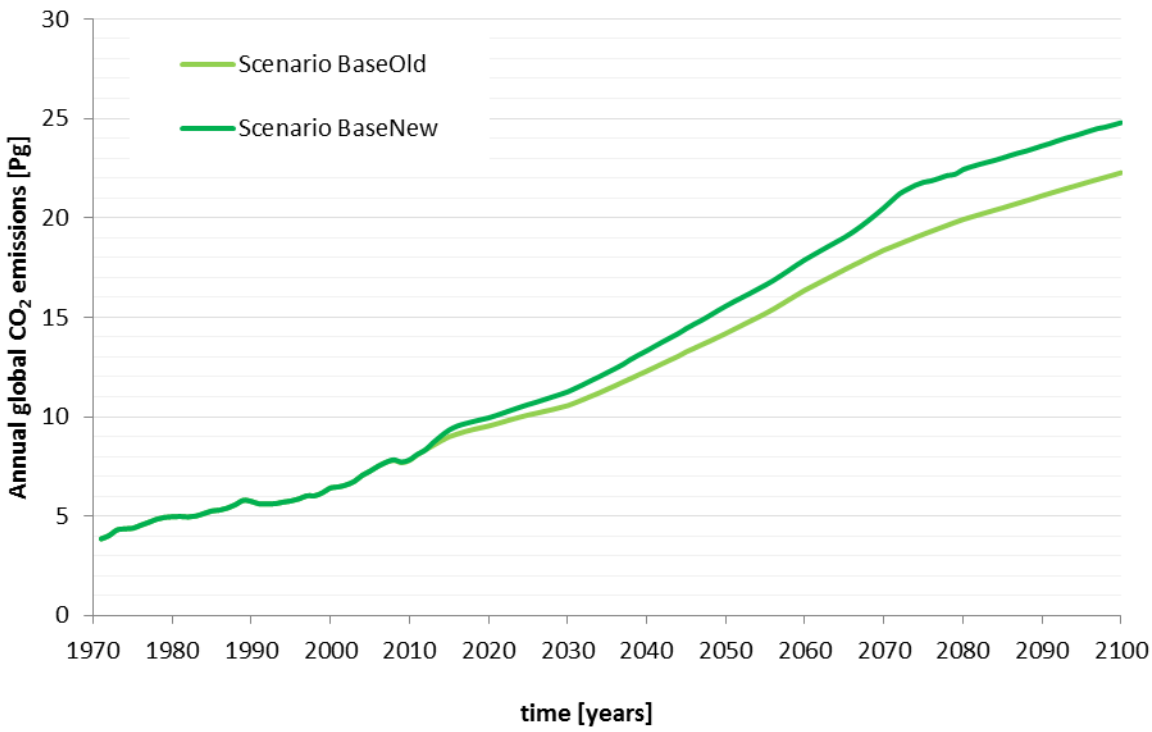


As shown in the figure, the ERE of gas starts increasing rapidly until 2050, after which it slightly stagnates. The difference in ERE with the original model BaseOld might explain the large difference in gas use as seen in Figure 4.11. The ERE for oil is initially increasing, until 2060 where there is a sudden large increase, simultaneously with the large increase in unconventional production as was seen in Figure 4.12. This is also quite different than in the BaseOld scenario, where there was a decreasing trend for the ERE. The large difference between the ERE of oil in BaseNew and BaseOld also explains the large difference in annual oil use seen in Figure 4.11. Another interesting aspect is that the ERE of gas in the original model was higher for most of the time than the ERE of oil, whereas in the updated model the EREs show large differences. The ERE of coal is decreasing in both scenarios BaseNew and BaseOld, although at a slightly higher initial value in BaseNew.

4.3.2. CO_2 emissions in the baseline scenarios

Another important aspect of the increased primary energy use of fossil energy carriers are the increased corresponding CO_2 emissions. Figure 4.15 gives an overview of the development of the total worldwide CO_2 emissions. The data is calibrated on historical data until 2011. As shown in the figure, total emissions increase at a higher rate in the updated model than in the original as a result of the higher indirect energy demand until 2100. Furthermore, the rate of total emissions is slowing down after 2070, resulting from a peak in oil use. Total emissions are projected to be around 10% higher in 2050 in the updated model compared to the original TIMER model. The largest difference between the original model and the updated model occurs around 2075, in which the emissions are projected to be almost 14% higher in the updated model, leveling out until 2100 with a 13.5% higher projection. This can also be seen from Figures 4.11 and 4.14, as around 2075 the largest differences occur between scenarios BaseOld and BaseNew.

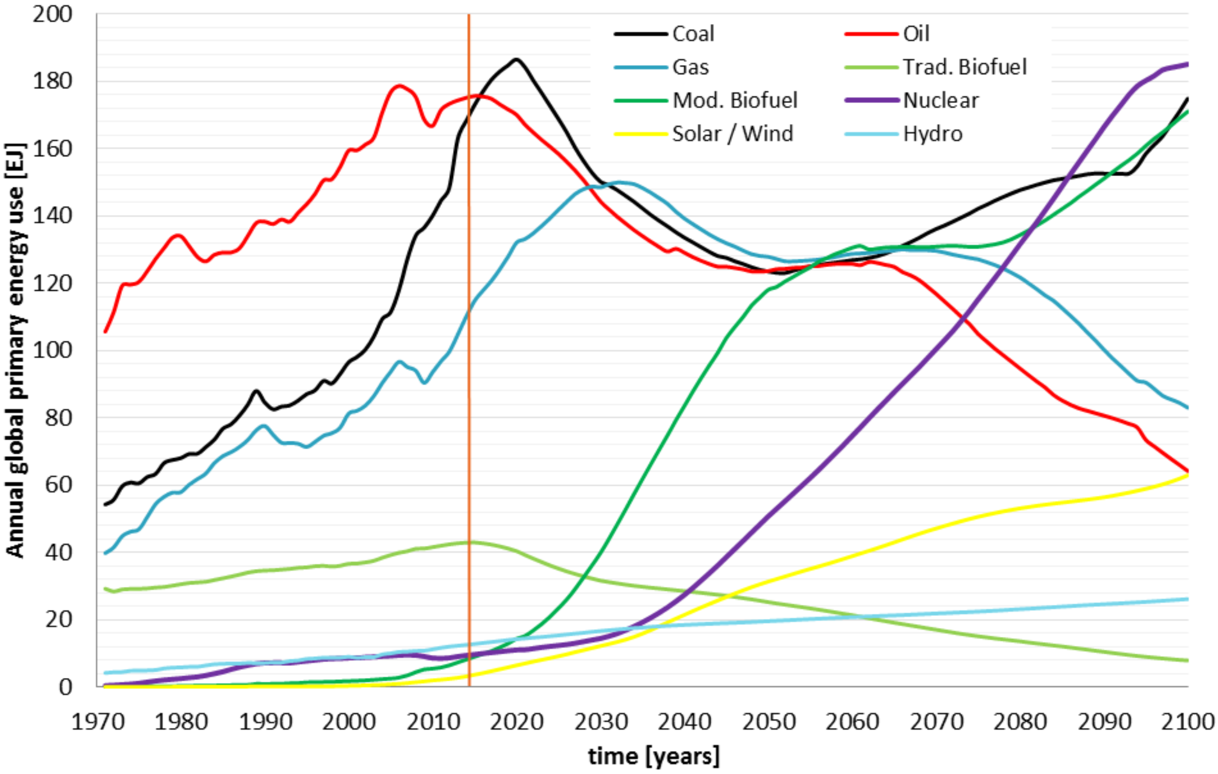
Figure 4.15. Projected annual global CO_2 emissions, from 1970 until 2100, for scenarios BaseOld and BaseNew.



4.3.3. Energy use in the mitigation scenarios

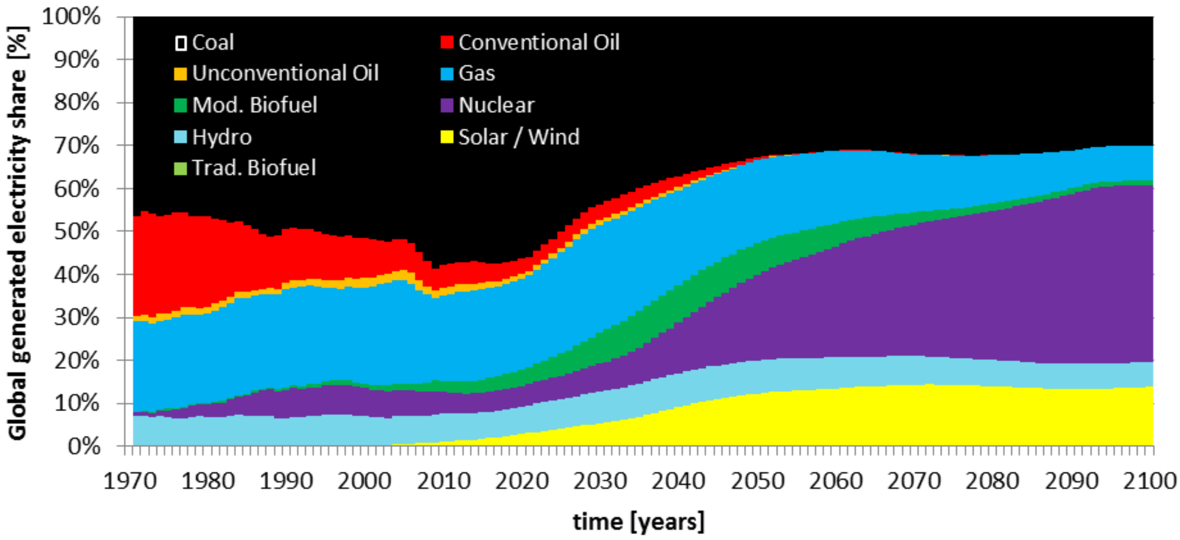
The mitigation scenarios describe a situation where global climate policy has resulted in a carbon tax on CO_2 emissions. This linearly increasing global carbon tax runs from \$ 0.- to \$ 1,500.- per tonne of CO_2 equivalent, in a time frame from 2015 to 2100. First, the effects of introducing the carbon tax in the model will be briefly explained on the basis of the example in Figure 4.16.

Figure 4.16. Projected annual global primary energy use, from 1970 to 2100, for mitigation scenario MitigNewCtaxInd. The orange vertical line is the intersection with the year 2015, which is the introduction year of the carbon tax.



The carbon tax is introduced in the year 2015 on a basis of a price per tonne CO_2 equivalent. As can be seen from Figure 4.16, oil use peaks in 2015, the year in which a carbon tax is introduced. Coal use decreases fast after 2020, after which the use of renewable technologies (mainly for electricity) starts to increase. This is especially use of modern biofuels and solar and wind technologies. Gas has another minor disturbance around 2020, especially from the coal use that is dropping, after which not as much indirect gas demand is induced anymore. Gas use still increases after 2020, but after 2050 with the upcoming of CCS technology (see section 3.4), it decreases slightly, in favor of cheap coal and biofuels used in CCS systems. The biofuels combined with CCS result in negative emissions. The use of nuclear electricity and solar and wind electricity also increases at a fast rate after 2030 (also see Figure 4.17).

Figure 4.17. Projected global generated electricity share, from 1970 to 2100, for scenario MitigNewCtaxInd.



Comparison of primary energy use in mitigation scenarios

As briefly explained in section 3.4, several mitigation strategies were considered. First of all, a taxing on direct emissions was implemented in the original model and the updated TIMER model. The global primary energy use projections for those two scenarios (MitigOld and MitigNewCtaxDir) are compared in Figure 4.18 (see next page).

Similar trends can be observed as in Figure 4.16: oil use peaks in 2015, coal use peaks around 2020, and a minor disturbance occurs in gas use as a result of coal use change. There are some minor shifts in scenario MitigNewCtaxDir though, due to higher depletion rates occurring. As there is more demand for fossil energy carriers, the model in scenario MitigNewCtaxDir reaches fossil resource cost-curve categories slightly earlier than in scenario MitigOld, with corresponding higher costs involved. Therefore a slightly earlier and faster adoption rate of renewable energy use can be seen in modern biofuels as well as solar and wind energy.

In order to compare the effects of imposing a carbon tax merely on direct emissions and on direct plus indirect emissions, it would be fair to only compare likewise models. The updated model already has an increased primary energy use: regarding mitigation strategies, it would require a larger effort for to sequestrate CO_2 emissions below a certain level. Therefore, the comparison is made with scenario MitigNewCtaxDir and MitigNewCtaxInd, as depicted in Figure 4.19 on the next page. To make the method of taxing clear once again: in MitigNewCtaxDir only the emissions caused by direct consumption (in other words, the carbon content of the fuel itself) is taxed. In MitigNewCtaxInd both direct consumption and emissions resulting from energy losses upstream are taxed.

Figure 4.18. Projected annual global primary energy use, from 1970 to 2100, for scenarios MitigOld and MitigNewCtaxDir.

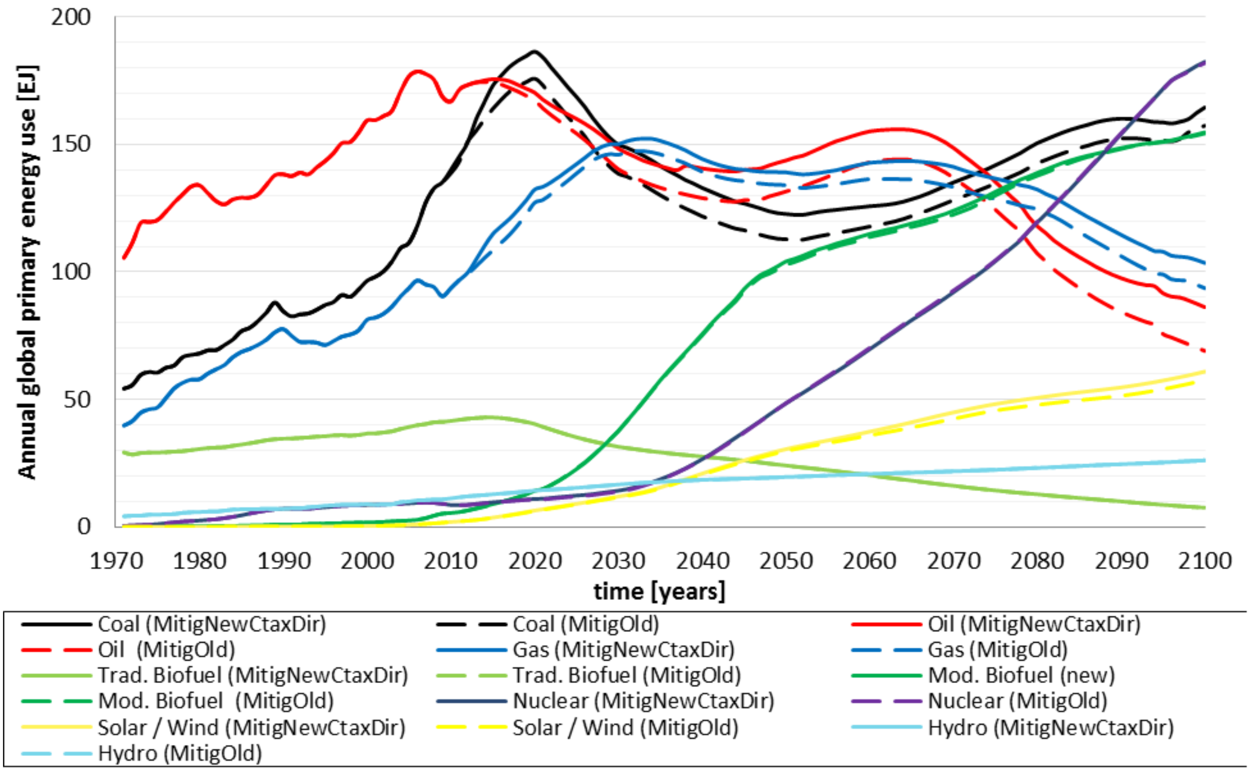
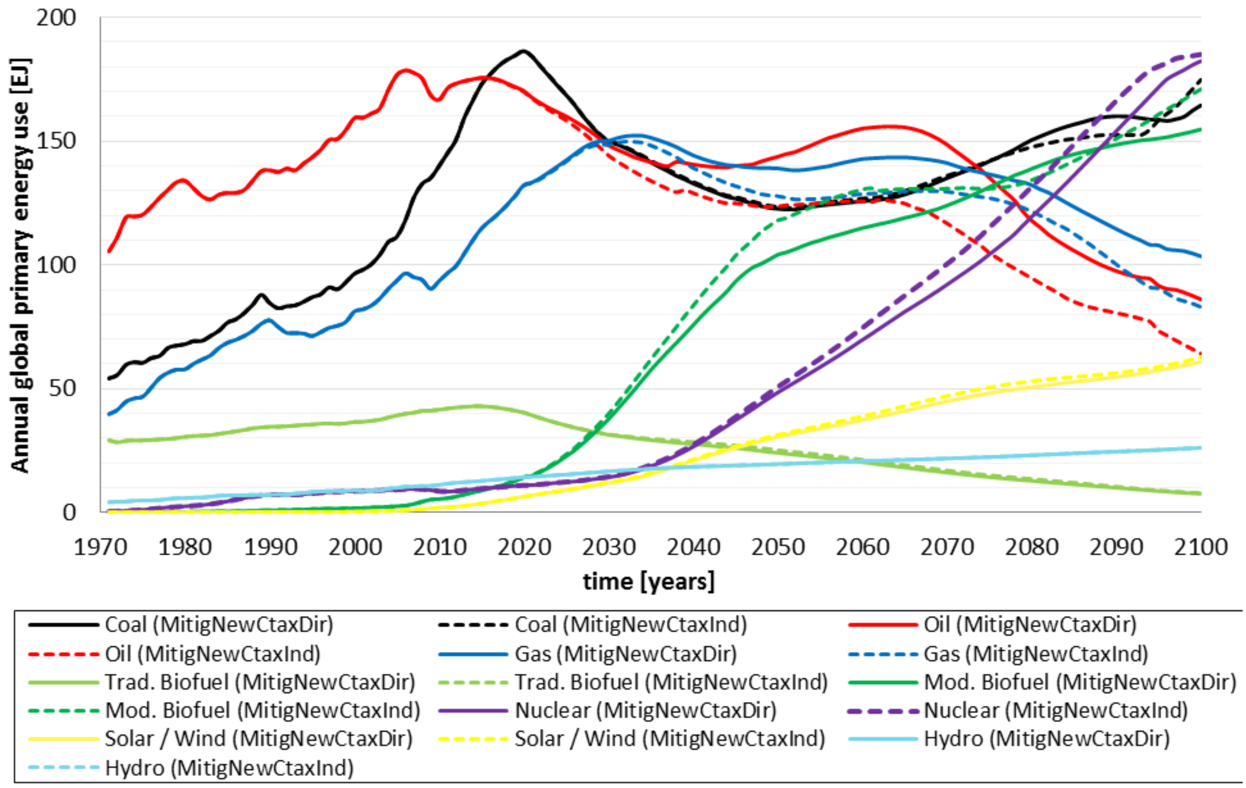


Figure 4.19. Projected annual global primary energy use, from 1970 to 2100, for scenarios MitigNewCtaxDir and MitigNewCtaxInd.

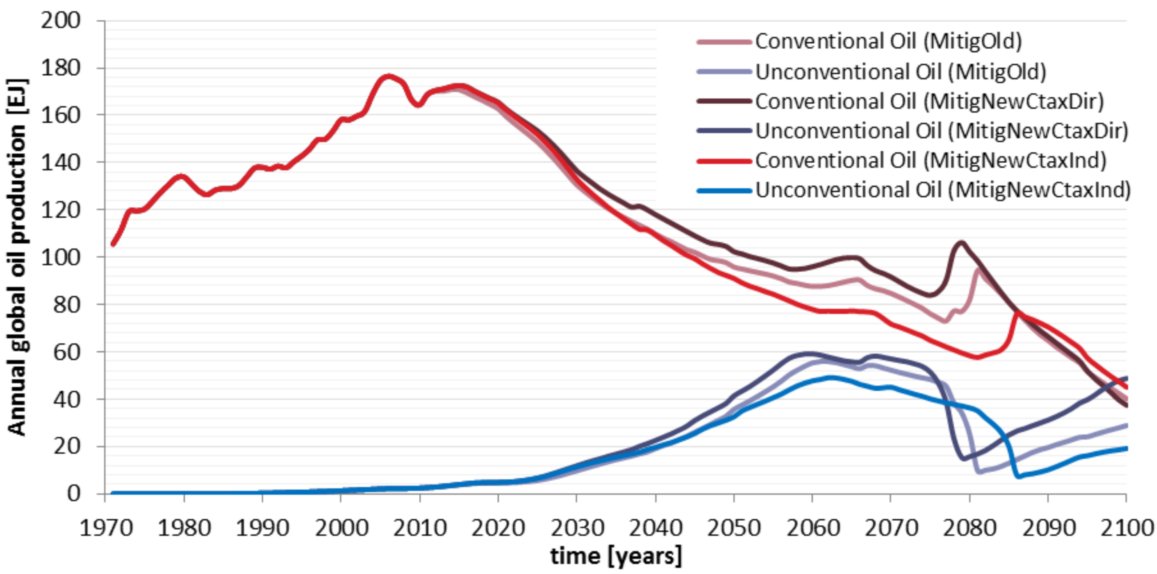


As can be seen in the comparison in Figure 4.19, a few events are occurring. The decrease in global oil use is going at a faster rate in scenario MitigNewCtaxInd, as for gas. Modern biofuel adoption is increasing at a higher rate initially, and after a levelling out around 2060, an extra increase occurs around 2080. These effects are primarily caused by the higher fossil fuel prices resulting from the extra carbon tax on indirect emissions, in which case oil is substituted for modern biofuels. Furthermore, there is a larger roll-out of nuclear energy than in scenario MitigNewCtaxDir; comparison with Figure 4.18 even shows a larger roll-out of nuclear electricity generation than scenario MitigOld, the original model mitigation scenario. This is also primarily caused by higher fossil fuel prices, but this time a substitution in fuel input for electricity occurs.

Oil production in the mitigation scenarios

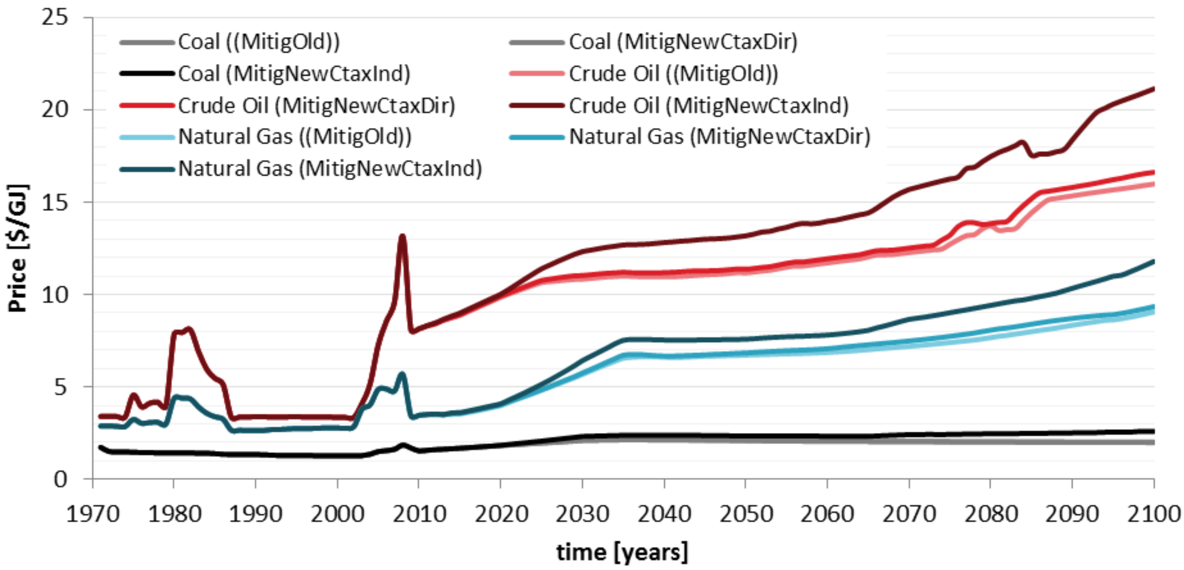
The comparison of oil production in the three mitigation scenarios is given in Figure 4.20. As was visible in the baseline scenarios (Figure 4.12), there is also a peak in unconventional oil production around 2060 in the three mitigation scenarios, although it is less steep and more evenly spread out over the decade 2060-2070. Afterwards, a peak in conventional oil production follows, after which unconventional slightly gains in market share again. Scenario MitigNewCtaxDir has an earlier peak with less duration than scenario MitigOld, as can be expected since oil use is generally higher and resources are depleted earlier. The same holds for the peak in conventional production.

Figure 4.20. Projected global conventional and unconventional oil production, from 1970 to 2100, for the three mitigation scenario MitigOld, MitigNewCtaxDir and MitigNewCtaxInd.



Scenario MitigNewCtaxInd however shows that unconventional oil production peaks at the same time as scenario MitigOld, although less high and more evenly spread out over the following years. The shock occurring is therefore somewhat soothed. Furthermore the second peak in conventional oil production is also lower and does not occur until around 2085. It can therefore be concluded that effective carbon taxing helps soothing shocks and prevents large spikes in oil production. The global fuel price development is given in Figure 4.21, which shows the prices increase at a faster rate in MitigNewCtaxInd than in the other two scenarios, because the indirect carbon tax is added to the fuel price.

Figure 4.21. Projected global price development of coal, crude oil and natural gas, from 1970 to 2100, for scenarios MitigOld, MitigNewCtaxDir and MitigNewCtaxInd. The spikes seen in 2008 indicate the sudden rise in global crude oil prices as a result from the financial crisis in 2008. The gas price was linked to crude oil price developments, coal price was also slightly influenced.



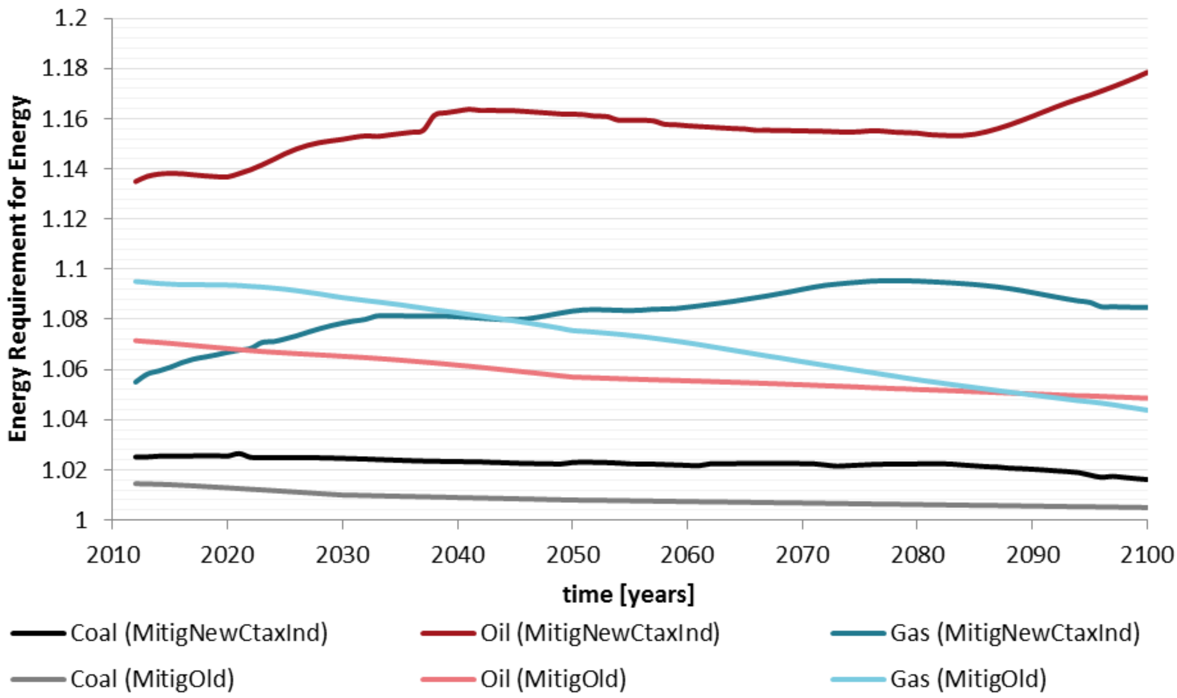
Indirect energy development in the mitigation scenarios

Figure 4.22 on the next page shows the development of the global average energy requirement for energy (ERE). All of the energy carrier inputs are summed: solid fuel, liquid fuel, gaseous fuel and electricity, divided by the average conversion efficiency. This is a first order ERE, as higher orders would have been influenced by EREs of other energy carriers. The ratio 1 : ERE can be seen as the ratio final energy : primary energy.

In comparison to scenario BaseNew in Figure 4.15, the EREs of oil and gas increase moderately in scenario MitigNewCtaxInd. Around 2050, the EREs of oil and gas were 1.18 and 1.11 respectively in scenario BaseNew, versus 1.16 and 1.08 in the mitigation scenario MitigNewCtaxInd. These trends continue to 2100 as the ERE of gas does not come above 1.10 in MitigNewCtaxInd, whereas it reached 1.12 in the baseline scenario BaseNew. For oil, the ERE in BaseNew in 2100 was 1.31, compared to an ERE of 1.18 in Mitig MitigNewCtaxInd in 2100. This is caused by less demand for oil, as can be seen from Figure 4.20, and especially less demand for energy intensive unconventional oil production, as seen in Figure 4.20. As there is less demand in general, oil production does not reach the higher, more expensive categories, that are also harder to produce in terms of energy requirement.

The development of the ERE of coal is similar to the one seen in the baseline scenario BaseNew in Figure 4.14 and has hardly changed. The EREs of the original model are exactly the same as in the baseline scenario BaseOld as they are exogenously put in the model and not calculated.

Figure 4.22. Projected global energy requirement for energy development, from 2015 to 2100, in scenarios MitigOld and MitigNewCtaxInd.



4.3.4. CO_2 emissions in the mitigation scenarios

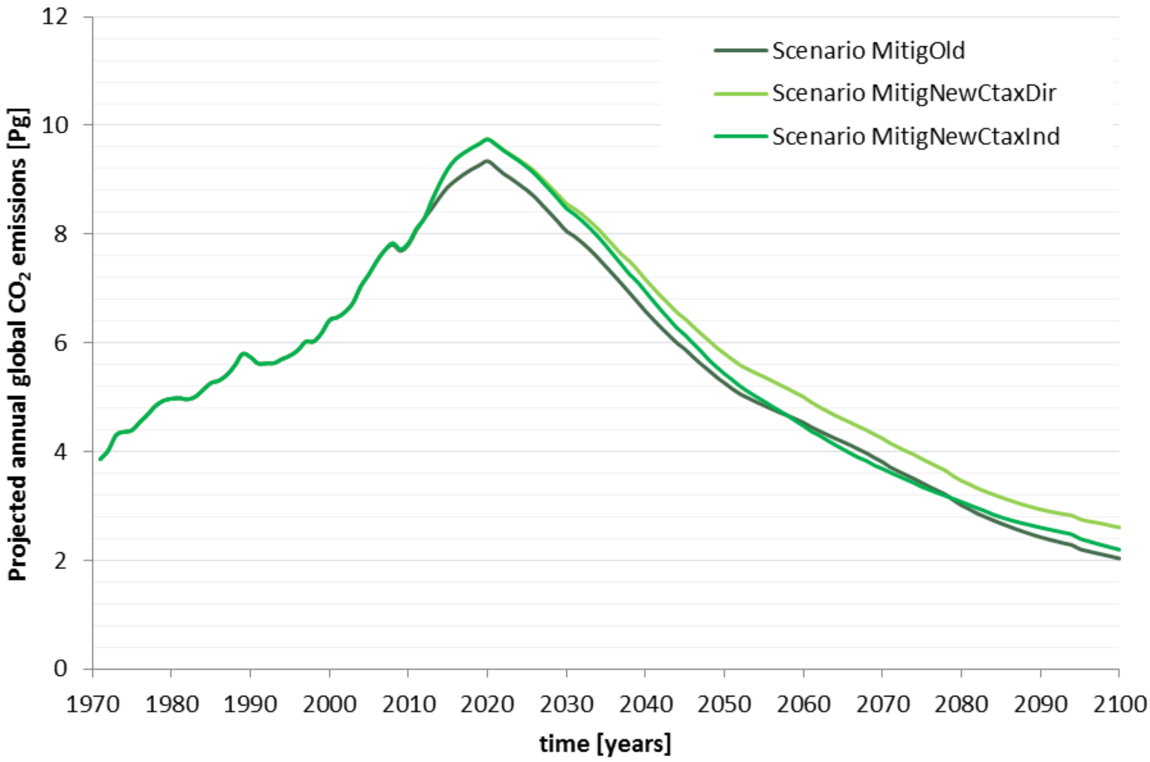
As was shown in the section on CO_2 emissions in the baseline scenarios, higher CO_2 emissions due to the higher global primary energy use is an important result of the updated model. The projected annual global CO_2 emissions are given in Figure 4.23 below. Annual emissions in scenarios MitigNewCtaxDir and MitigNewCtaxInd are initially higher than in scenario MitigOld, after which the difference in annual CO_2 emissions remains relatively constant between scenario MitigOld and MitigNewCtaxDir.

It would however not be fair to compare scenario MitigOld and MitigNewCtaxInd directly, as both the model setup (with or without modifications) and the carbon tax scheme are different (taxing only direct or both direct and indirect emissions). It would be fair to say that scenario MitigNewCtaxDir actually represents scenario MitigOld, if all projected upstream energy losses due to conventional or unconventional fossil resource production would be calculated accordingly.

CO_2 emissions in scenario MitigNewCtaxInd decrease at a faster rate than in scenario MitigNewCtaxDir. The fact that the rate of decrease is larger in scenario MitigNewCtaxInd indicates that the absolute higher fuel prices (due to incorporating also indirect emissions in the carbon tax) result in an extra energy use decrease. This is fairly logical: a higher absolute price results in a larger demand decrease.

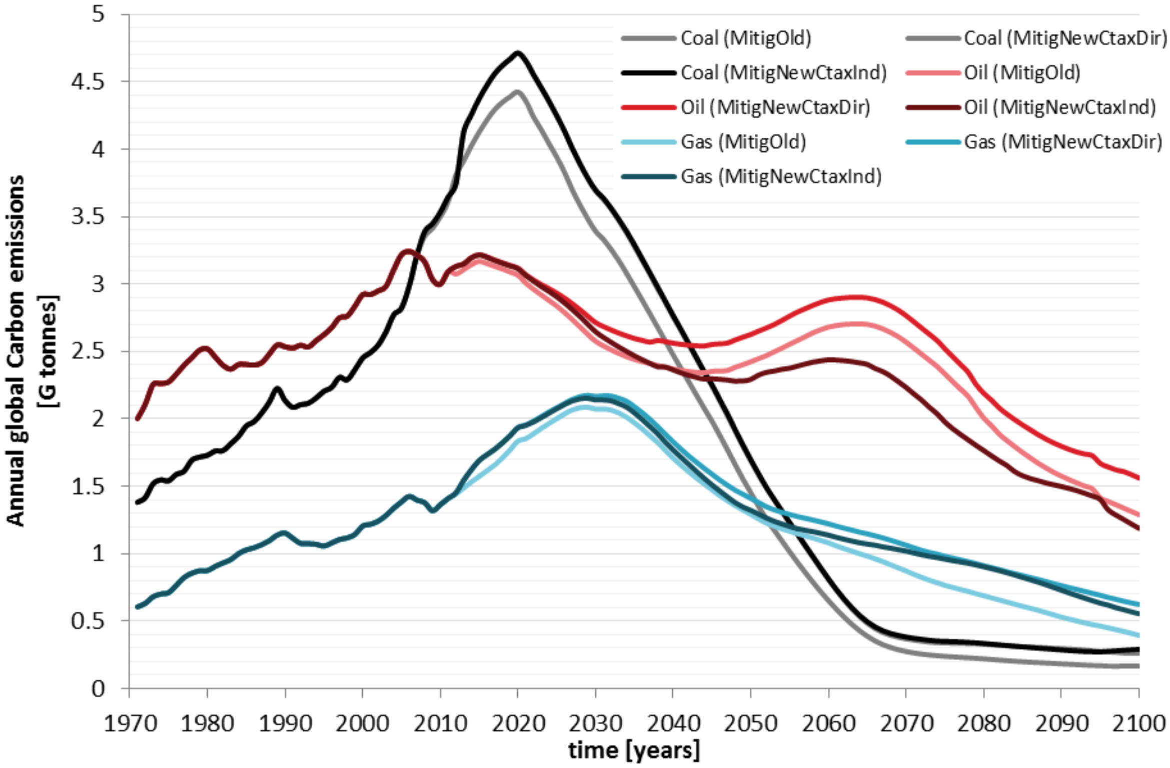
An important difference with the setup in the original model is that CO_2 emissions related to upstream incurred energy losses cannot be sequestrated, as a large part of the emissions occurs in operations without proper access to CO_2 capturing technology (i.e. coal-mining or unconventional oil production operations). On the other hand, with a slight effort and especially under high prices occurring in the mitigation strategies after 2050, it could be stated that CO_2 emissions from refining facilities, retorting operations and several coal and gas processes can be actively captured and stored. The implications of the assumption will be discussed analyzed in the Discussion.

Figure 4.23. Projected annual global CO_2 emissions from 1970 to 2100, in scenarios MitigOld, MitigNewCtaxDir and MitigNewCtaxInd.



The subdivision of these CO_2 emissions is given in Figure 4.24. Coal-related CO_2 emissions are the same for scenario MitigNewCtaxDir and MitigNewCtaxInd; the difference with scenario MitigOld is constant until the year 2060, after which it decreases slightly. The reason that the coal related CO_2 emissions are decreasing so fast and do not show a resemblance to primary energy use of coal anymore after 2030 is because of the incorporation of CCS combined electricity generation in the electricity mix (see section 3.4 for an explanation). The measure lowers the total coal-related CO_2 emissions drastically; the technology does the same for gas related CO_2 emissions after 2040.

Figure 4.24. Projected annual global CO_2 emissions per fuel type, from 1970 to 2100, in scenarios MitigOld, MitigNewCtaxDir and MitigNewCtaxInd.



Oil-related CO_2 emissions differ between the scenarios. Initially oil-related emissions are the same for scenario MitigNewCtaxDir and MitigNewCtaxInd, and are larger than in scenario MitigOld. Between 2025 and 2035 oil-related emissions in MitigNewCtaxInd decrease at a faster rate though, after which they remain fairly constant until around 2065. The other two scenarios see an increase in oil related CO_2 emissions after 2040, with a second peak around 2065. After 2065 the oil related emissions decrease again until 2100. The reason for the sudden emissions increase after 2040 in scenarios MitigOld and MitigNewCtaxDir, and the difference with scenario MitigNewCtaxInd, is in pricing. After Canadian cheap and easily accessible oil is being depleted, the model can easily pass to higher cost-curve categories without having to take into account that these categories are less accessible and have higher corresponding CO_2 emissions from their higher upstream energy use. As the model in scenario MitigNewCtaxInd does take in account the higher carbon taxes related to higher emissions from production, this effect is soothed, keeping oil demand slightly constant between 2040 and 2065 instead of increasing.

5. Sensitivity analysis

To measure the sensitivity of the model to certain variable changes, a sensitivity analysis was performed. First an analysis will be performed where energy inputs for fossil resource production are kept constant from 2011 on. Secondly, an analysis will be performed on the energy inputs and related trends towards the future, by setting an annual percentage increase and decrease. Finally, an analysis is performed for the incorporation of fugitive emissions for other unconventional gas types than only shale gas.

5.1. Case studies of unconventional production methods and trends in energy use

The energy analysis of unconventional fossil resource production methods was based on several case studies. Trends of unconventional energy inputs were based on conventional statistics, which already incorporated both the depletion aspect and technological aspect of energy inputs [Dale, 2010]. The trend seen is the net effect of both aspects (see section 4.1). It could be stated that energy inputs will decrease more rapidly over time in unconventional resource production than in conventional resource production, as unconventional production is often based on new and immature production and process techniques. As a result, the efficiency improvement rate would be higher for unconventional production than the one already incorporated in the trends of conventional production. An argument against underestimation of unconventional learning rates is the fact that case studies have been used to determine the energy requirement for production of unconventional resources. These studies are be based on operations that are currently being deployed and can therefore be seen as the low hanging fruit of the total unconventional resource potential.

An adjacent aspect for uncertainty is that the trend lines chosen and extrapolated are based on a relative small amount of the total fossil resource base (cumulative production being only a small fraction of total potential resources).

As these trends mainly have to do with future developments of energy inputs, the sensitivity of the results will be looked into by incorporating higher or lower energy inputs. The exact range of learning rates to be tested in the sensitivity analysis can be debated, as the efficiency in the conventional fossil resource industry is already incorporated in the net effect. Blok [2007] stated that as a rule of thumb efficiency in industry improves by 0.75% annually. Krausmann et al. [2009] did research on energy intensity of the global economy and found that it decreased by 0.68% over the period 1900 to 2005. Based on these findings, the lower limit for the sensitivity analysis was set at 1% decrease of energy inputs per year. The upper limit is set at 1% increase of the energy inputs per year.

These amounts will have accumulated to energy input multipliers of 2.4 and 0.4 in 2100. In other words, the energy inputs will be 2.4 times the amounts in 2012 in the highest scenario, and 0.4 times the amounts in 2012 in the lowest scenario[20], in 2100.

First, a scenario will be analyzed in which there are no trends in energy inputs, and the assessed energy inputs stay constant from the year 2011 on for all three energy carriers.

5.1.1. Results sensitivity in a scenario with constant energy inputs

Figure 5.1 shows the annual global primary energy use in scenario BaseNew and a scenario in which energy inputs are kept constant (Constant scenario). Conventional fossil resource production energy inputs are kept constant at 2011 levels (as found in the IEA extended balances [IEA, 2014]), unconventional fossil resource production energy inputs are kept constant at the levels as assessed in section 4.2 from the case studies.

In Figure 4.1, coal use increases more over time in BaseNew than in the Constant baseline scenario, as the electricity use for fossil fuel production increases. The same holds for the gas use increase, although it also increases because gas inputs in oil production are increasing. Oil use slightly increases from 2030 to 2070 because oil production requires more oil, although the later categories do not require as much anymore, indicated by the oil use in BaseNew being slightly lower than in the scenario with constant energy inputs. Other energy carriers than fossil did not change and were therefore left out of the graph. This also impact the projected annual global CO_2 emissions, as can be seen in Figure 5.3.

Figure 5.2 and Figure 5.3 show a comparison between the annual global primary energy use and CO_2 emissions of scenario MitigNewCtaxInd and the Constant mitigation scenario. The same trends as in the baseline scenario comparison from section 4.3 can be seen here, as overall less energy is required in the Constant scenario compared to MitigNewCtaxInd. From 2045 to 2075 and from 2090 to 2100, there is more gas use in the Constant scenario. This is the result of substitution effects within the model, as fuel prices are lower in general in the Constant scenario compared to in the MitigNewCtaxInd scenario. Prices are lower, because energy inputs do not follow the increasing trends over time, resulting in a higher carbon tax if upstream energy losses are incorporated.

The Constant scenario also shows that the energy inputs are increasing in BaseNew and MitigNewCtaxInd. From 2011 on, the same difference occurs in the comparison between the Constant scenario (Base or Mitig) and BaseNew/MitigNewCtaxInd, as in the comparison between the BaseOld/MitigOld and BaseNew/MitigNewCtaxInd. The differences that occur in coal and gas from 2011 on are due to the increasing electricity requirement in fossil fuel production.

[20] A quick calculation gives: $101\%^{(2100-2012)} = 2.40$ and $99\%^{(2100-2012)} = 0.41$

Figure 5.1. Comparison of projected annual global primary energy use in BaseNew (solid line) and the scenario where energy inputs are kept constant (dotted line), from 1970 to 2100. Conventional production energy inputs are kept constant at the 2011 levels, unconventional production energy inputs are kept at the levels as assessed in section 4.2. Other energy carriers than fossil did not change and were therefore left out of the graph.

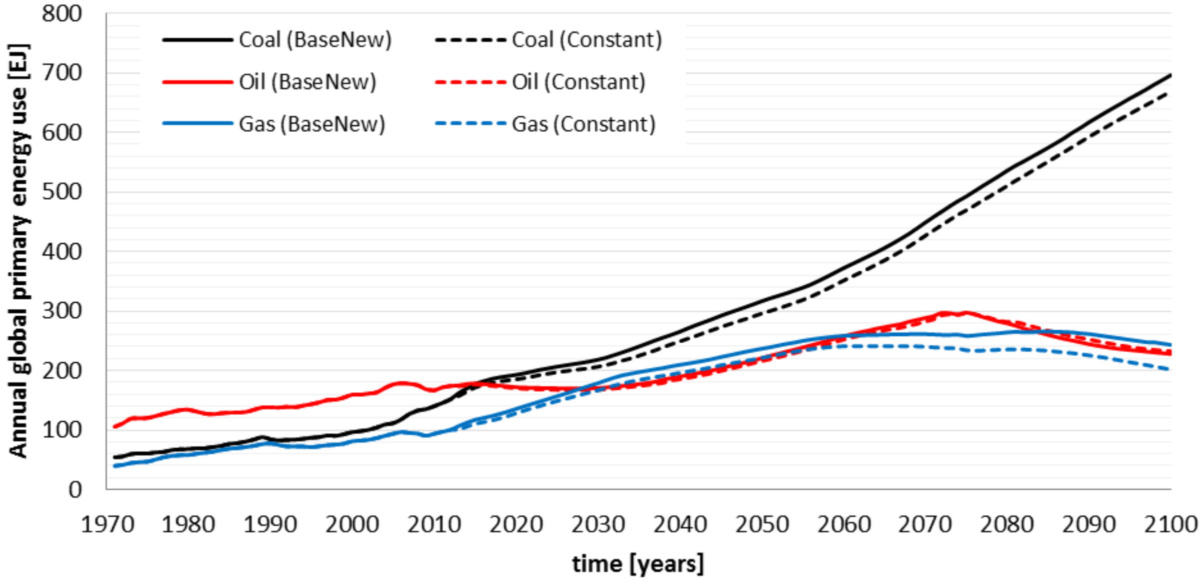


Figure 5.2. Comparison of projected annual global primary energy use in MitigNewCtaxInd (solid line) and the scenario where energy inputs are kept constant (dotted line), from 1970 to 2100. Conventional production energy inputs are kept constant at the 2011 levels, unconventional production energy inputs are kept at the levels as assessed in section 4.2.

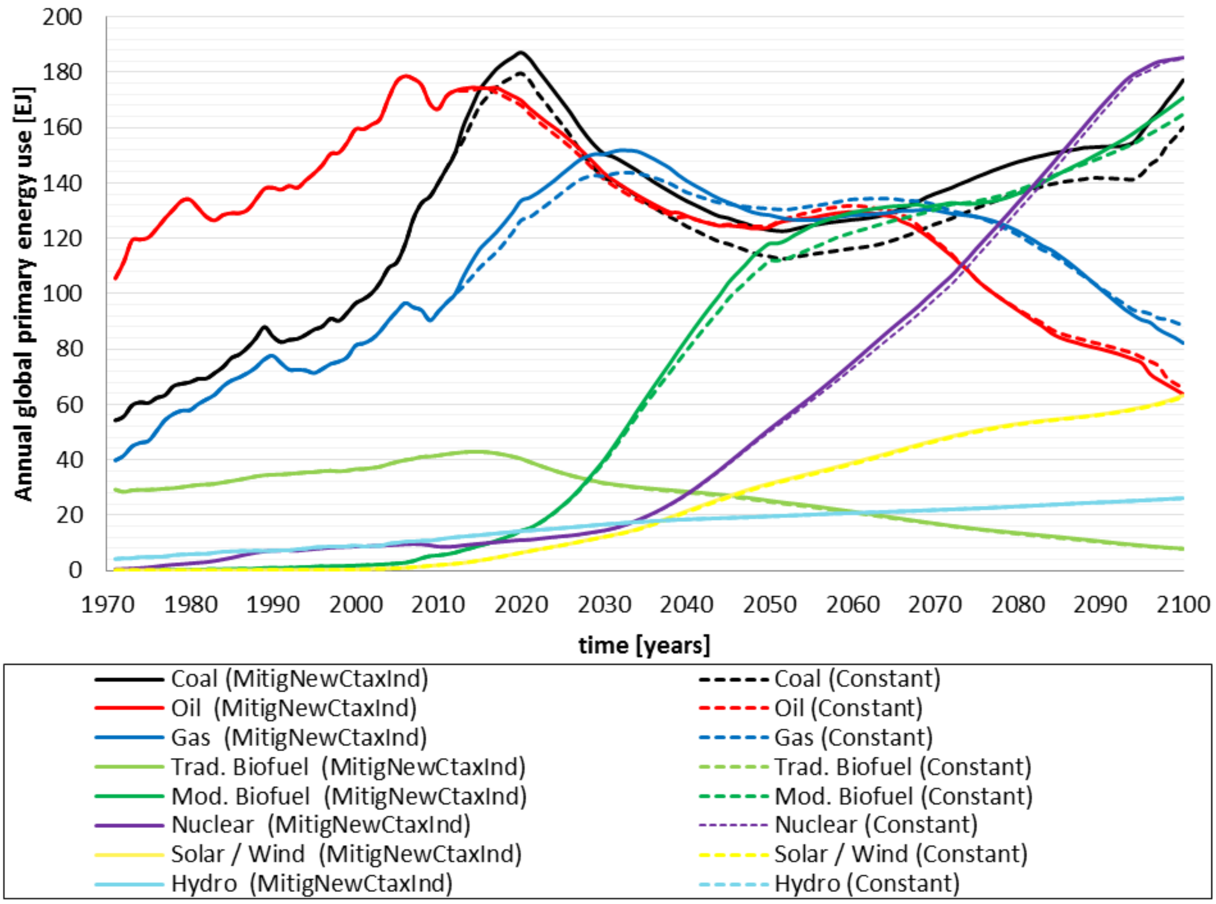
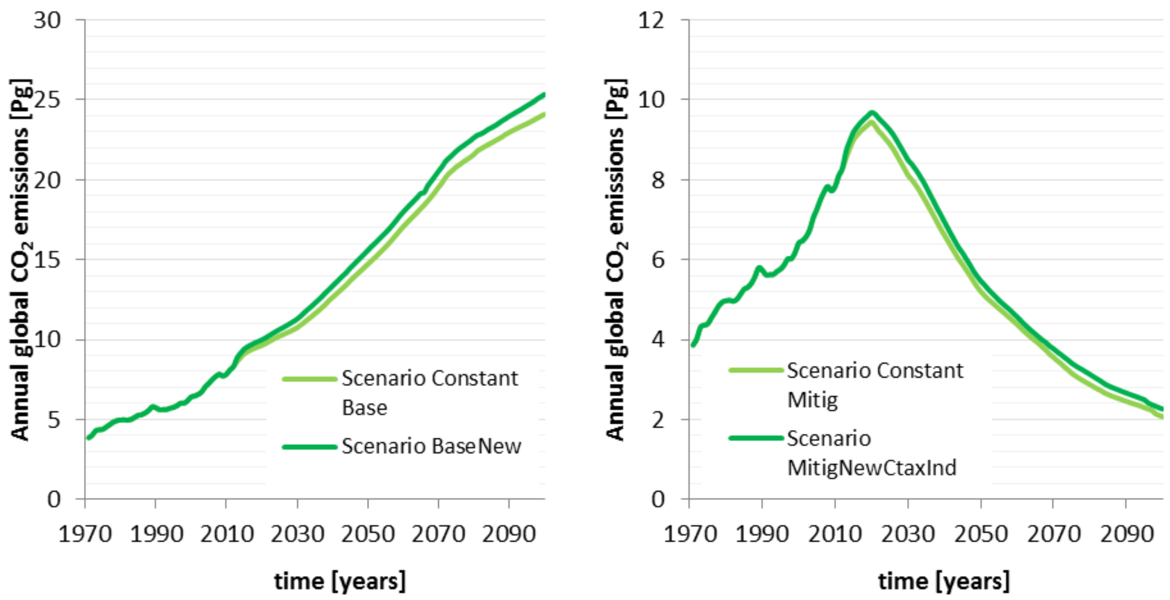


Figure 5.3. Projected annual global CO_2 emissions in BaseNew (left graph), MitigNewCtaxInd (right graph), and the scenario where energy inputs are kept constant in baseline (left graph) and in mitigation (right graph), from 1970 to 2100. Conventional production energy inputs are kept constant at the 2011 levels, unconventional production energy inputs are kept at the levels as assessed in section 4.2.



5.1.2. Results sensitivity to changing energy requirements

The sensitivity of the model to changes in conventional and unconventional energy requirements for production and processing will be measured by looking at the annual global primary energy use and CO2 emissions. They were assessed for the baseline scenario BaseNew and mitigation scenario MitigNewCtaxInd (see section 3.4 for the scenario description).

Results sensitivity to changing energy requirements in baseline scenario BaseNew

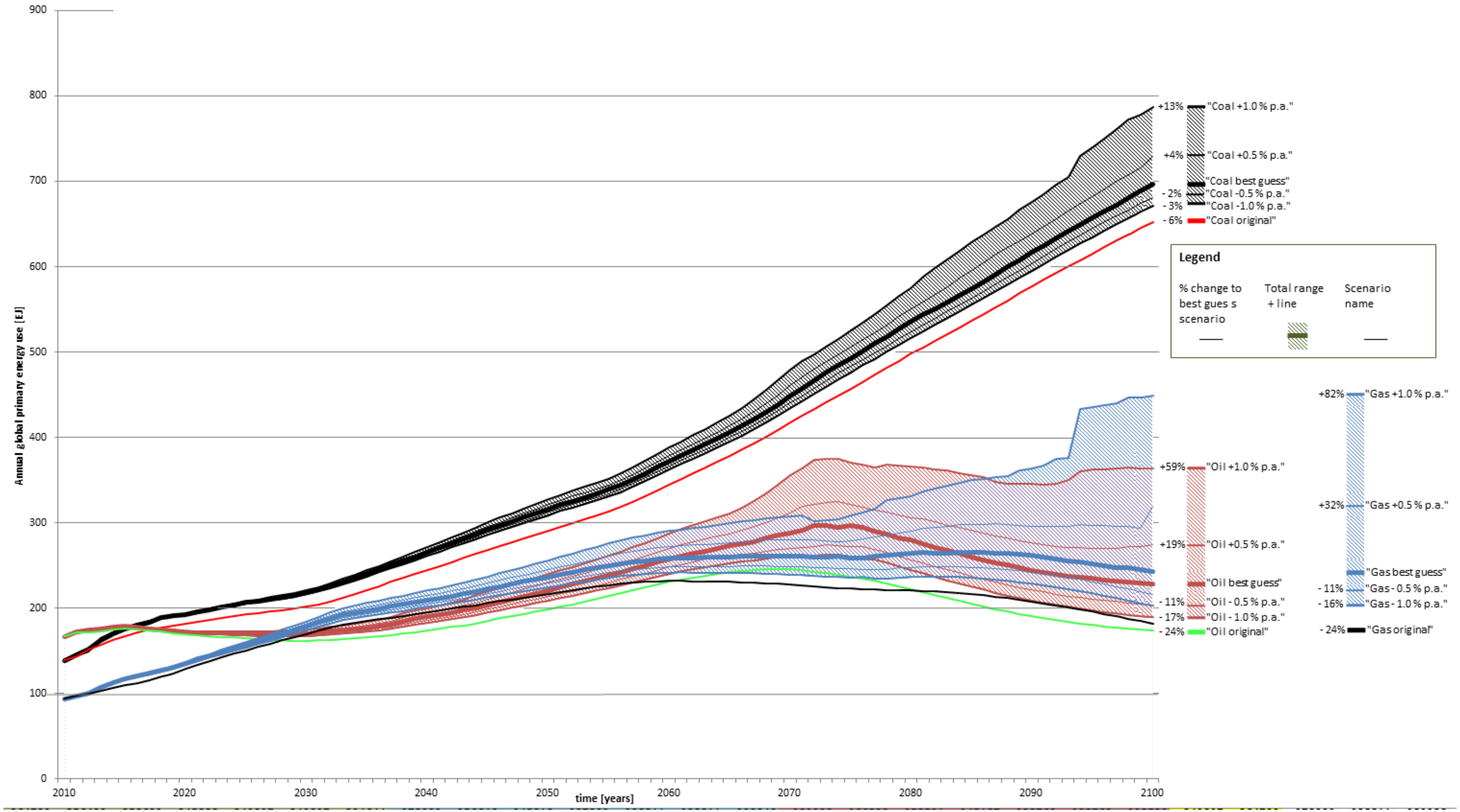
Figure 5.4 shows the change in annual global primary energy use for the energy carriers coal, oil and gas as a result for the change in energy requirements. Figure 5.5 shows the aggregated primary energy use.

The sensitivity analysis has been performed by varying the energy inputs of oil and gas production within the range from 1% higher per year to 1% lower per year. This results in an either an exponential increase or decrease of the energy requirement.

Figure 5.4 shows that coal use is quite sensitive to higher energy requirements for oil and gas demand. This was expected, as coal is a cheap option in the baseline scenario for the extra electricity generation required for oil and gas production. Even in the scenario with the lowest energy requirements, there is still a discrepancy of 3% with the coal amount in the original model.

Annual global primary oil and gas use are very sensitive to changes in energy requirements for oil and gas production and processing, as shown in Figure 5.4.

Figure 5.4. Sensitivity analysis of projected annual global primary coal, oil and gas use to changing energy requirements for oil and gas in the TIMER model in BaseNew, from 2010 to 2100. The input changes used run from 1% extra energy inputs per year (+1%, as indicated by the upper bold line) to 1% lower energy inputs per year (-1%, also efficiency, as indicated by the lower bold line). Please see text for` further explanation. The red, green and black lines indicate developments for coal, oil and gas respectively in the original model.



Towards the future, 0.5% extra efficiency improvement in fossil resource production per year results in a 11% lower oil use in 2100. On the other hand, worsening of energy requirements of 0.5% per year would result in 19% higher annual oil use. A 1% annual increase in energy requirements results in an increase from 32% to 82% in additional gas demand around 2090 compared to the baseline scenario BaseNew. This results from reaching a production category with very high energy inputs. Figure 5.1 showed that oil use in the Constant scenario was about the same as BaseNew. The lowest oil scenario of 1% decrease per year still shows a difference of 7% with the original model, indicating the original was a low estimate in general.

Figure 5.5. Sensitivity analysis of projected annual total primary energy use to energy inputs for oil and gas in the TIMER model in BaseNew, from 2010 to 2100. The efficiency progressions used run from 1% extra energy inputs per year (+1%, as indicated by the upper most bold line) to 1% lower energy inputs per year (- 1%, also efficiency, as indicated by the lower most bold line). Please see text for further explanation. The green line indicates the original model.

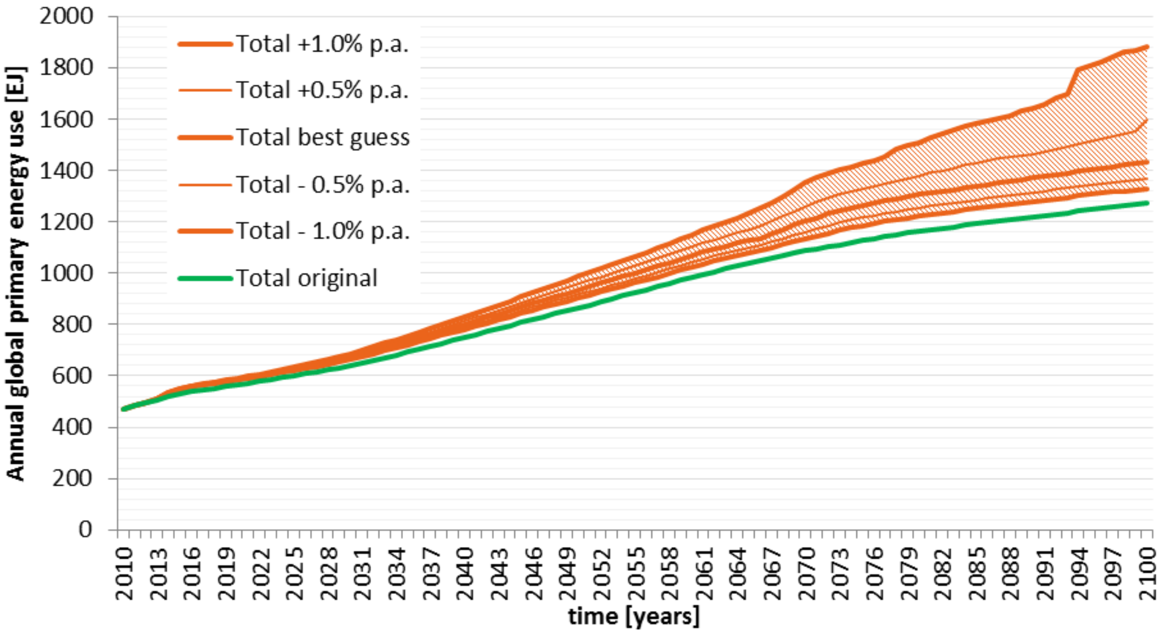
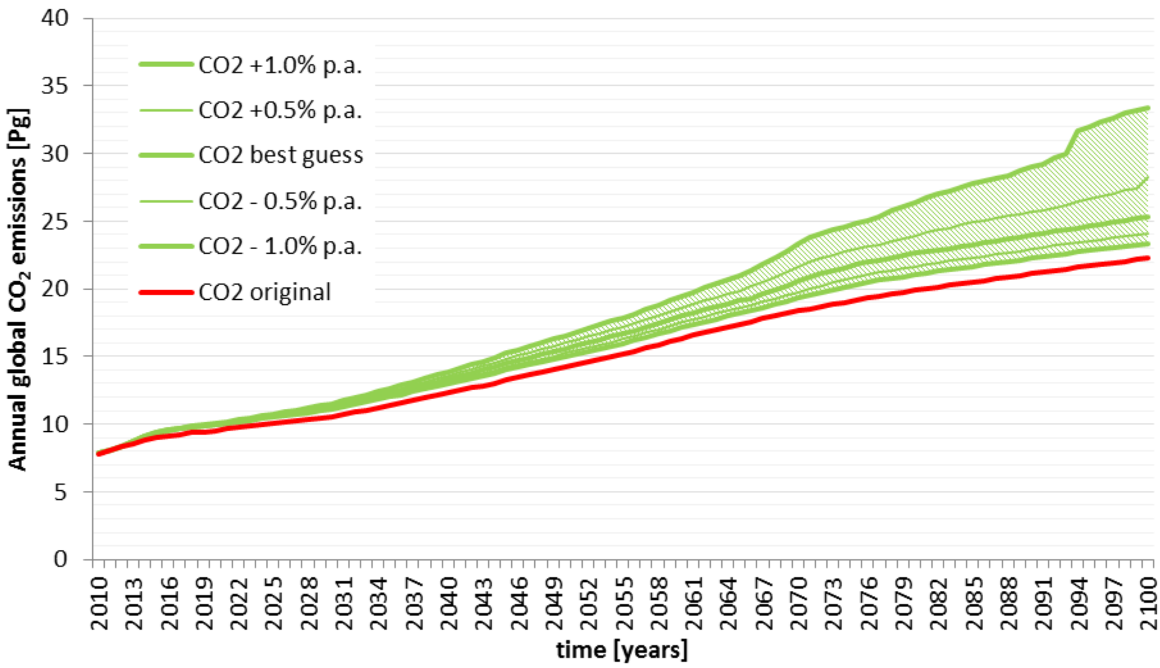


Figure 5.5 shows that the sensitivity of total energy use in the more outlying scenarios (1% higher and lower energy inputs per year) is dependent on the change in the use of fossil energy carriers. In the 1% higher energy inputs per year scenario, total energy use is about 31% higher, while in the 1% lower energy inputs per year scenario total energy changes to only about 7% lower. Additionally, even the largest decrease of energy inputs per year results in a total energy that is 5% higher than in BaseOld.

Figure 5.6 shows the sensitivity of annual global CO_2 emissions to the changes in energy inputs. This graph is quite analog to the graph of total energy in Figure 5.5. The figure shows that the model is more sensitive to higher energy inputs than to lower energy inputs regarding emissions as well. Even the scenario with the lowest energy inputs still has more CO_2 emissions per year globally than the original model.

Figure 5.6. Sensitivity analysis of projected annual global CO_2 emissions to energy inputs for oil and gas in the TIMER model in BaseNew, from 2010 to 2100. The efficiency progressions used run from 1% extra energy inputs per year (+1%, as indicated by the upper most bold line) to 1% lower energy inputs per year (- 1%, also efficiency, as indicated by the lower most bold line). Please see text for further explanation. The red line indicates the original model.



Results sensitivity to changing energy requirements in mitigation scenario MitigNewCtaxInd

Figure 5.7 shows the change in annual global primary energy use for the energy carriers coal, oil and gas as a result for the change in energy requirements. Figure 5.8 shows the aggregated primary energy use.

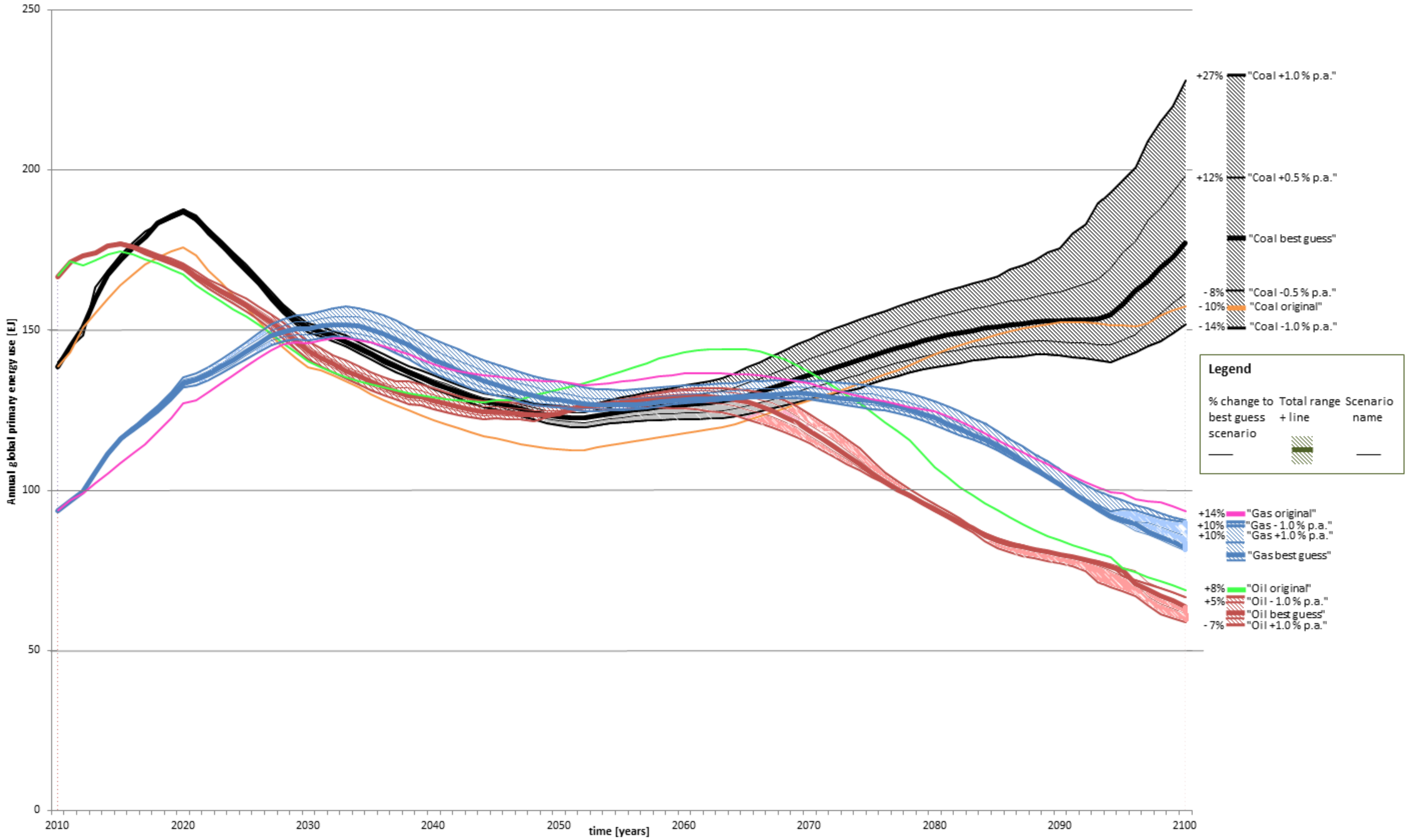
The sensitivity analysis has been performed by varying the energy inputs of oil and gas production within the range from 1 % higher per year to 1% lower per year. This results in an either an exponential increase or decrease of the energy requirement.

Figure 5.7 shows that coal energy use in the model is quite sensitive to higher inputs for oil and gas demand in the mitigation scenario. As stated in the previous section on the coal sensitivity graph, this is logical, as coal is a cheap solution for electricity generation. Even though there is a carbon tax present, if coal is combined with CCS for electricity generation, these taxes are avoided. The upstream energy losses for coal are negligible as was already seen in section 4.3. Additional research also showed a larger roll-out of nuclear energy, although this is not shown in graphs in the research. Gas however is a more expensive electricity fuel because of the relatively large upstream energy losses. The carbon tax is imposed on the emission resulting from upstream losses, even if the direct emissions can be sequestrated in the CCS plants. Figure 5.7 also shows that coal use is sensitive to lower energy inputs as there is no need anymore for extra electricity generation. This is indicated by the 14% reduction in coal use in 2100, if energy inputs for oil and gas production decrease with 1% per year.

Figure 5.7 shows that coal energy use in the model is quite sensitive to higher inputs for oil and gas demand in the mitigation scenario. As stated in the previous section on the coal sensitivity graph, this is logical, as coal is a cheap solution for electricity generation. Even though there is a carbon tax present, if coal is combined with CCS for electricity generation, these taxes are avoided. The upstream energy losses for coal are negligible as was already seen in section 4.3. Additional research also showed a larger roll-out of nuclear energy, although this is not shown in graphs in the research. Gas however is a more expensive electricity fuel because of the relatively large upstream energy losses. The carbon tax is imposed on the emission resulting from upstream losses, even if the direct emissions can be sequestrated in the CCS plants. Figure 5.7 also shows that coal use is sensitive to lower energy inputs as there is no need anymore for extra electricity generation. This is indicated by the 14% reduction in coal use in 2100, if energy inputs for oil and gas production decrease with 1% per year.

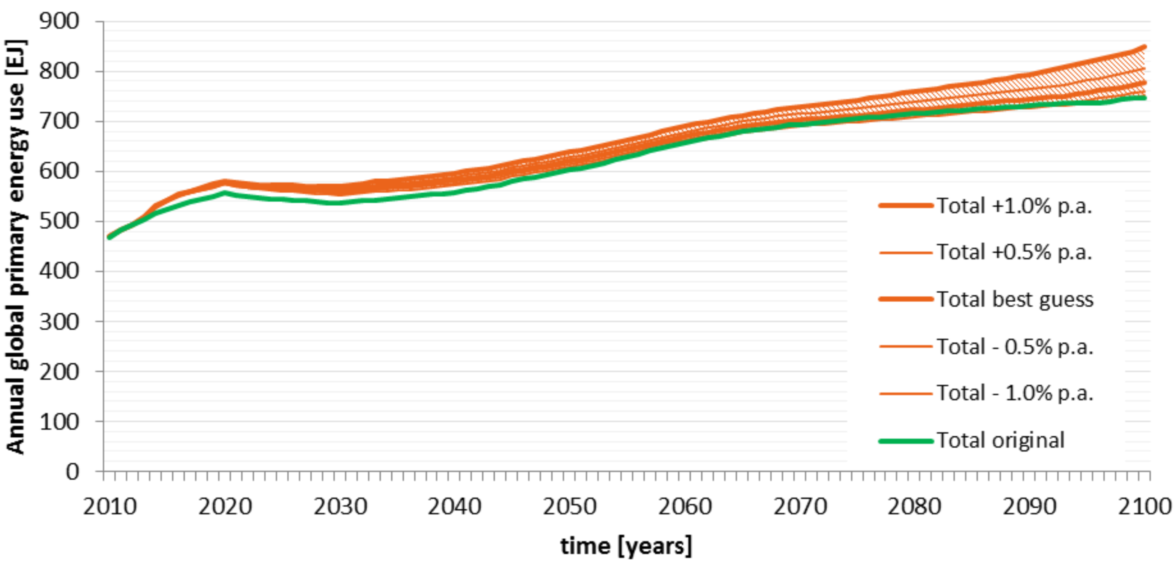
For oil and gas use, there are some shifting points due to sensitivities to energy inputs for oil and gas production. For the sensitivity of oil use, there is a general pattern visible though. Until 2050, the scenarios gradually expand at first and converge after 2040. Around 2050 there is a shifting point after which lower energy inputs lead to higher oil use and worsening energy inputs lead to less oil use. This can be explained through pricing. Since more energy-intensive oil (higher energy inputs) comes at a higher price due to the incorporated carbon tax, it is less attractive to consume oil, and it is substituted by other energy carriers. On the other hand, oil with low energy inputs comes at a lower price and is more easily chosen within the preference mechanisms in the model. This also explains why the oil use in the original model is a lot higher than in the other scenarios. Since the energy requirement for production is not incorporated in the carbon tax that is imposed, the tax added to the price is much lower than in scenario MitigNewCtaxInd. In general, oil use in the mitigation scenario is much less sensitive to changing energy inputs than in the baseline scenarios, when comparing Figures 5.4 and 5.7.

Figure 5.7. Sensitivity analysis of projected annual global primary coal, oil and gas use to energy inputs for oil and gas in the TIMER model, as a percentage change to the best guess scenario BaseNew. Performed with different annual efficiency progressions in scenario MitigNewCtaxInd, from 2010 to 2100. The efficiency progressions used run from 1% extra energy inputs per year (+1%, as indicated by the upper bold line) to 1% lower energy inputs per year (-1%, also efficiency, as indicated by the lower bold line). Please see text for further explanation. The orange. green and pink lines represent the lines for coal, oil and gas respectively in the original model.



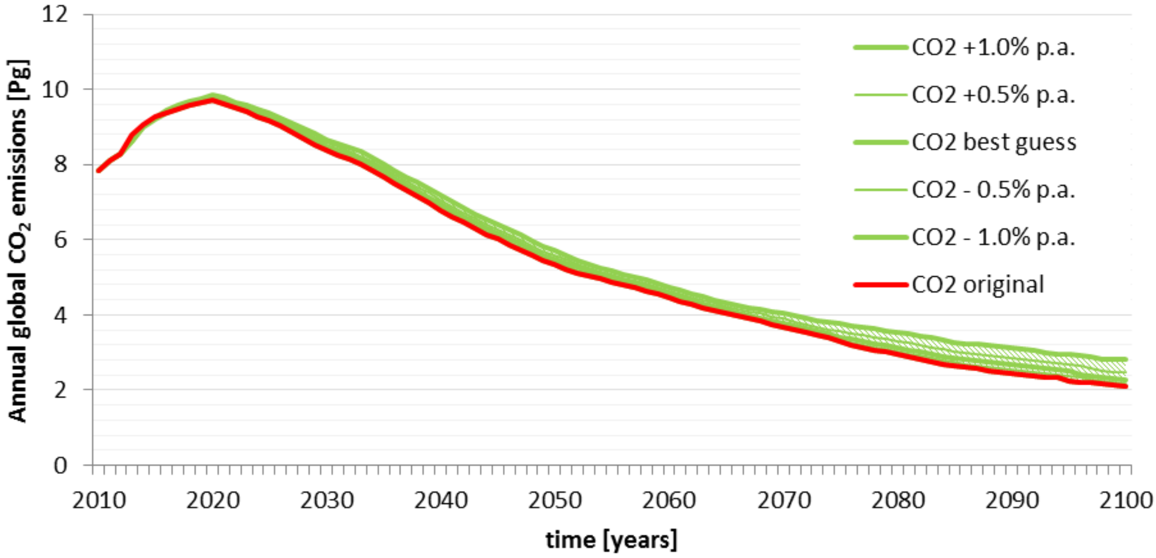
The same substitution mechanisms hold for annual global primary gas use, with a shift around 2090 in the mitigation scenario MitigNewCtaxInd. An odd result is that both higher and lower energy inputs lead to a higher natural gas use in 2100 than in the best guess scenario of MitigNewCtaxInd, except for the more moderate scenario with a 0.5% energy requirement increase per year. These results have different explanations. In the higher energy requirement scenarios, there is more gas use anyway, which is not substituted for other energy carriers. This can be because of gas requirements for oil production or gas requirements for electricity, which is needed for oil and gas production. In the lower energy requirement scenarios, the relatively low upstream energy losses lead to a less high carbon tax for indirect emissions. This makes gas a more favorable fuel, in which case gas demand rises and increases primary annual gas use.

Figure 5.8. Sensitivity analysis of projected annual total primary energy use to energy inputs for oil and gas in the TIMER model in MitigNewCtaxInd, from 2010 to 2100. The efficiency progressions used run from 1% extra energy inputs per year (+1%, as indicated by the upper bold line) to 1% lower energy inputs per year (- 1%, also efficiency, as indicated by the lower bold line). Please see text for further explanation. The green line indicates the original model.



The range of scenarios for total annual primary energy use in MitigNewCtaxInd is given in Figure 5.8, which shows a lower sensitivity to changing energy inputs than Figure 5.5 for BaseNew. The influence of fossil energy carriers is less, as the energy mix is more evenly distributed (also see Figure 5.3). When energy inputs would decrease by 1% per year, the total energy use in the mitigation scenario would change by less than 5%. Annual global CO_2 emissions about equally sensitive to changing energy requirement as total annual primary energy use in the mitigation scenarios (see Figure 5.9).

Figure 5.9. Sensitivity analysis of projected annual global CO_2 emissions to energy inputs for oil and gas in the TIMER model in MitigNewCtaxInd, from 2010 to 2100. The efficiency progressions used run from 1% extra energy inputs per year (+1%, as indicated by the upper bold line) to 1% lower energy inputs per year (-1%, also efficiency, as indicated by the lower bold line). Please see text for further explanation. The red line indicates the original model.



5.2. Results sensitivity to fugitive CH_4 emissions for tight gas and coalbed methane

An important aspect of unconventional gas production is that shale gas production has incorporated high fugitive CH_4 emissions. Since the other gas types are based on extrapolations of conventional gas production figures, it is assumed that these figures already have incorporated fugitive CH_4 emissions in their energy and emission profiles. It could however be that due to the relatively new state of technology (hydraulic fracturing), these fugitives were not completely accounted for in the statistics.

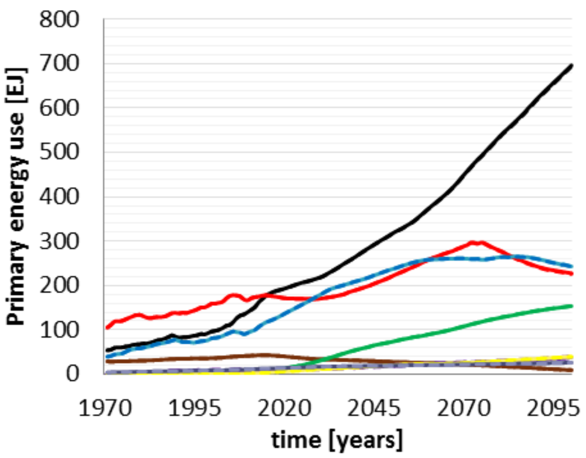


Figure 5.10. Comparison of annual global primary energy use in BaseNew (solid line) and the scenario where fugitive CH_4 emissions are added to tight gas and coalbed methane (dotted line), from 1970 to 2100. The colors for the energy carriers are the same as in other graphs, also see Figure 5.1.

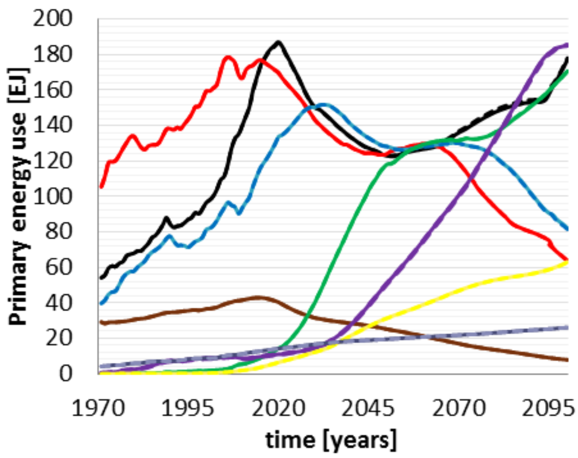


Figure 5.11. Comparison of annual global primary energy use in MitigNewCtaxInd (solid line) and the scenario where fugitive CH_4 emissions are added to tight gas and coalbed methane (dotted line), from 1970 to 2100. The colors for the energy carriers are the same as in other graphs, also see Figure 5.2.

A comparison was made to test the sensitivity of the model with regard to changes in fugitive methane emission. In the first scenario fugitive methane emissions only result from shale gas production. In the second scenario, these fugitive emissions result from tight gas production and coalbed methane production as well. The comparison has been made for both a baseline and a mitigation world. As shown in Figures 5.10 and 5.11, changes to the amount of fugitive methane emissions does not influence the outcomes of scenarios. The reason is that these energy inputs are quite small in the total energy profile of these gas types and that tight gas and coalbed methane also have low shares in the global unconventional gas mix. The fugitive emissions should be accounted for other aspects than merely energy though, as the fugitive emissions are methane with a global warming potential of 86 over 20 years [IPCC, 2013]. For more information on fugitive emissions in unconventional gas production, please see reports by Howarth et al. [2011] and Deijns [2014].

6. Discussion

The sensitivities as discussed in section 5.1 will be given some qualitative argumentation. Besides the uncertainties, there are a few other assumptions in the research worth looking into. These will be treated according to the related subject, subdivided by 1) energy inputs and trends in fossil resource production, 2) energy carriers, 3) emissions and environmental aspects and 4) the TIMER model.

6.1. Energy inputs and trends in fossil resource production

Since no adequate data was found for the production of extra heavy oil, tight gas, coalbed methane and deep gas, assumptions regarding their energy inputs were made. Figures 4.6 and 4.7 show that the energy inputs of production of these unconventional resources are in the same order of magnitude as the ones for which data was gathered. This might not be adequate enough as large differences are possible, although possibilities for higher or lower energy requirements were tested in the Sensitivity analysis, and will be further discussed below.

For the other unconventional resource types, production data was derived from case studies. It can be debated whether this case specific data is applicable for all production efforts of these resource types, both now and in the future. It is important to stress that current unconventional resource production techniques are often far from being fully developed. Moreover, other production techniques might rise in the future, but these can not be anticipated yet. The gathered case studies gave the best possible estimates that are currently available, as not much literature was present.

The exact energy input trends chosen as described in section 3.3 could be debated as well, as they are prone to change in the future. The high uncertainty involved with extrapolating trends to potential production amounts (in the TIMER categories) based on current cumulative production leads to question whether it would be fair to use trends at all and use an other method of determining future energy inputs for fossil resource production. It is however known that energy inputs for production undergo the effects of both depletion and technological progress [Dale, 2010]. The net effect seen in the historical energy inputs already incorporated these two effects. Keeping the energy inputs constant from 2011 figures gave some differences in Figures 5.1 and 5.3, although energy and emissions were still higher than in the original model. As there was ambivalent argumentation to change the energy inputs even more over time (low hanging fruit vs. efficiency progress) the author chose to extrapolate current trends.

The considerations of section 5.1 in the Sensitivity analysis lead to the conclusion that total primary energy use and corresponding CO_2 emissions might differ from the best guess scenario shown, although they are probably higher than the ones shown in the original model. Further research into case studies on the energy production profiles of these unconventional fossil resources could solve these uncertainties.

Whether future energy input trends for unconventional resource production can be based on energy inputs for conventional resource production is debatable, since the techniques deployed for unconventional production seem different. As was stated in section 3.3, techniques for retorting and upgrading are rather similar to refining techniques, and will probably follow these decreasing trends in energy in the future. As was shown in section 4.2, retorting and upgrading make up for a large share in the energy production profile of unconventional resources. It could be that the trends for these techniques deviate from conventional refining techniques, for which possible results were shown in section 5.1. Other parts of the production process of, for example, oil sands and oil shale surface mining are similar to coal mining. These parts make up for only a small amount in the total energy profile though. Finally, downstream processing for unconventional resources are the same as for conventional fuels, as for example Synthetic Crude Oil is sometimes even of higher quality than conventional crude oil [Brandt, 2009].

6.2. Energy carriers

It could be argued that some of the allocation of energy carriers show inconsistencies. For example, petroleum cokes are historically allocated to oil products, but are allocated to solid fuels in the updated model. This could possibly lead to some future discrepancies. Also, the assumption has been made that these cokes are directly used (see section 4.2). These cokes were being stockpiled in Canada, instead of being used directly [AER, 2004]. There are however more and more business cases around for example Canadian petroleum cokes, as they sometimes even cheaper than natural gas for electricity generation [New York Times, 2013; Murthy et al., 2014].

The embodied energy in infrastructure was not accounted for in the energy requirements. As seen in Figures 4.7 and 4.8, embodied energy in infrastructure represents only a small fraction of the total energy requirements, so the effects of this shortcoming are expected to be minimal. Other studies show that unconventional gas production methods could use up to four times as much steel than conventional gas production methods [Norgate & Jahanshahi, 2011]. This would be worth looking into for future studies.

6.3. Emissions and environment.

This research only focuses on the effects of energy and corresponding CO_2 emissions resulting from conventional and unconventional fossil resource production and processing, on total energy use. Other environmental impacts resulting from, for instance, water use, land use change, fugitive emissions or other local pollutions are not accounted for. As fugitive CH_4 emissions for shale gas production, for example, are high it would be worth looking into what potential climate effects would be. Please also see studies by Howarth et al. [2011] and Deijns [2014].

6.4. TIMER model

For the TIMER model, several considerations should be taken in account.

An important notion to begin with is that production costs within the cost-curves of fossil resources were not updated in the model and not made dependent on energy carrier inputs, since no adequate data was available. This would possibly lead to differences within the baseline scenario, as production costs are affected. In the mitigation scenario differences would potentially be lower, as adding a carbon tax on upstream emissions of energy carriers indirectly incorporates these costs.

In this analysis, no substitution within the energy requirements is possible (except for the electricity sector, see Stehfest et al. [2014]). Substitution could be rewarding in case of large changes in fossil resource prices. This would lead to lower total costs, an optimization of fuel use and possibly to less upstream energy demand. On the other hand: some of the energy inputs are not easily substituted. For heating, multiple energy carriers can be used, and substitution between these energy carriers is often pretty straightforward. In other processes, energy carriers are not that easily substituted, which leads to the fact that only part of the inputs can be changed.

Another point of discussion is the aggregation of oil products into solid fuel, liquid fuel and gaseous fuel, which is dependent on the current mix of products. The spectrum of oil product requirements could be more adequately assessed through life cycle assessments if TIMER contained a more detailed distinction between oil products. This would particularly be rewarding for the model, when the mix of fuel products would change in the future.

Energy inputs of TIMER categories are now based on a weighted average of the amounts of resource types in a certain region (e.g. oil sands in Canada, extra heavy oil in Venezuela). A slightly better approach would be to have separate categories for each resource type, as their production methods also differ.

It would also be interesting to look into possibilities to have the same integral order approach for the production of other energy carriers within the model, such as biofuels, nuclear energy or other forms of electricity generation, and renewables. This would incorporate the life cycles of these energy carriers as well, for which this research has provided some methodological foundations. These fuels could therefore also be inputs for the fossil resource industry, making all of the energy carriers interdependent.

Regarding the carbon tax, it would be interesting to analyze the effects of imposing the carbon tax in the mitigation scenarios on different levels of the supply chain. The carbon tax is now imposed after trade, based on the local emission factors of the producing regions. It would be interesting to see what the effects are if it were imposed before trade or even at production. This would then require producers to actively choose whether it would be viable to produce 'dirty' resources at all, possibly reducing CO_2 emissions and energy use even more effectively.

A final remark is that in the mitigation scenarios, the assumption was made to not have the possibility to sequestrate CO_2 emissions from upstream activities, even in fuels for CCS. This could be argued, as prices are an important driver for behavior in general. The added carbon tax on indirect emissions could result in companies adding extra carbon sequestration to their activities. For upstream activities this could mean active CO_2 capturing from fossil resource production or processing like oil refining and coke-ovens. This was however not possible to do anymore with the given time constraints, as this would require a link with CCS parts in the model. It would be recommended to look into for future research.

7. Conclusion

The fossil resource base is vast and can supply the world's energy demand for quite some time in terms of potential amounts available in the subsurface. However, when regarding the increasing energy requirements for production of these resources, feasible amounts may very well be only a fraction of the total. The low hanging fruit of unconventional fossil resources being picked now is not representative for all the resources. Further stages in unconventional resource production may add substantial amounts of indirect energy to the total energy demand. The resulting CO_2 emissions are substantially higher than originally projected, adding more pressure on efforts to sequestrate emissions. This leads to believe that further research on energy requirements of fuel production may be an important factor to look into for other future projections on energy and emissions as well, as literature on the subject is quite scarce.

The baseline scenario in this research projects an 8% higher primary energy use in 2050 and even 13% higher in 2100, compared to originally projected figures. These changes are primarily to the credit of an increase in fossil primary energy consumption, having increased 9.5% and 16% in 2050 and 2100. Corresponding CO_2 emissions resulting from these changes are projected to be 10% higher annually in 2050 and 13.5% in 2100. Even in case of larger technological progress, the annual global primary energy use and CO_2 emissions were still about 5% higher than in the original model, indicating a significant difference.

As unconventional oil was projected to be the dominant oil resource after 2070, the higher energy requirements for production induced substantial demand for other sources as well. As depletion progresses at a higher rate, this indirect energy demand increases even further.

In the mitigation scenario the relative differences in primary energy use and CO_2 emissions between the original and updated model were smaller than in the baseline scenario, but only when the carbon tax incorporated upstream energy losses as well. The large roll-out of unconventional oil production was omitted, avoiding large indirect energy requirements. There were large differences with the scenario with only a direct carbon tax, which left the annual CO_2 emissions at a level of 15% to 20% higher towards the end of the century. This indicates that it would be beneficial to look into fuel life cycles and incorporate these losses as well, when considering an effective carbon tax.

In general, due to the higher prices involved, fossil fuels were easily substituted for other energy carriers. In scenarios with higher energy requirements, the opposing effects of higher energy use and more substitution canceled each other out. Lower energy inputs (thus higher efficiency improvement) had the same effects: lower prices due to lower inputs make fossil fuels more attractive for substitution, but there is lower energy use in general. The range over the scenarios was therefore very small, indicating higher or lower energy requirements do not matter for the results much.

The energy inputs for oil sands production and upgrading showed that a significant amount of energy was required for production (54% of the energy content of the product), although this amount is reduced to about 30% if co-products are incorporated. Synthetic crude oil fabricated from oil shale required most energy inputs of the unconventional oil types with an indirect energy of 54% of the energy content of the product. Extra heavy oil requires low energy inputs for production. The upgrading adds a significant amount of energy requirement though, resulting in an indirect energy of 18% of the energy content of the product. These amounts were projected to decrease in the future, as processes of upgrading and retorting are similar to refining techniques.

The production processes of unconventional oil are mostly self-sufficient, as a substantial amount of energy in supplied by internal energy inputs. In financial terms, these inputs are cheap, which also would slightly refute the incentive to improve efficiency in the baseline scenario, since emmisions do not have a financial penalty and resources are vast. This financial incentive would be present in the mitigation scenario, although changing the energy requirements (higher efficiency) were shown to not result in large changes.

Shale gas' production energy requirements are 11.5% of the energy content of the product, which is higher than conventional gas. As gas is an important fuel for fossil resource production, developments in the production energy requirements result in an overall energy and CO_2 emissions increase.

An important thing to acknowledge for the research is that there were uncertainties regarding energy use for fossil resource production. But, since this is inherent to future energy and climate modelling, the most important aspect is to understand what those uncertainties are, test assumptions and try to analyze possible outcomes if inputs, parameters or model relations do turn out differently.

7.1. Recommendations for further research

Particular recommendations for further research would be on the viability of the energy inputs used for unconventional resource production. Due to a lack of data in literature, assumptions were made and tested. There could be more certainty regarding these exact energy inputs if more case studies would be performed.

Other aspects worth looking into are other impacts than merely on energy and emissions of unconventional resource production. These consist of costs involved, water use, land use change, fugitive emissions or other local pollutions.

For the TIMER model it would be interesting to look into a further separation of energy resources and energy carriers within the model. This would open up more accurate paths of research on the influence of these aspects on future energy use and emissions.

Finally, regarding carbon taxing, it would be of importance to see what the influence would be of imposing carbon taxes in different parts of the supply chain. The taxes were added after trade, although it would be interesting what the effects are when these taxes were imposed at production. Besides, the addition of extra CO_2 sequestration possibilities would be recommended.

The author briefly looked into these two possibilities but the results were left out because of time constraints.

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Annexes

Annex A: TIMER regions, GEA regions, corresponding countries and conversion between TIMER and GEA regions.

Table A 1. TIMER regions and their corresponding countries and area codes [Mulders et al., 2006].

TIMER Region No.	Country Name	ISO 3166 code A 3	ISO 3166 code Number
1	Canada	CAN	124
2	St. Pierre and Miquelon	SPM	666
	United States	USA	840
3	Mexico	MEX	484
4	Anguilla	AIA	660
	Aruba	ABW	533
	Bahamas, The	BHS	044
	Barbados	BRB	052
	Belize	BLZ	084
	Bermuda	BMU	060
	Cayman Islands	CYM	136
	Costa Rica	CRI	188
	Cuba	CUB	192
	Dominica	DMA	212
	Dominican Republic	DOM	214
	El Salvador	SLV	222
	Grenada	GRD	308
	Guadeloupe	GLP	312
	Guatemala	GTM	320
	Haiti	HTI	332
	Honduras	HND	340
	Jamaica	JAM	388
	Martinique	MTQ	474
	Montserrat	MSR	500
	Netherlands Antilles	ANT	530
	Nicaragua	NIC	558
	Panama	PAN	591
	Puerto Rico	PRI	630
	St. Kitts and Nevis	KNA	659
	St. Lucia	LCA	662
	St. Vincent and the Grenadines	VCT	670
	Trinidad and Tobago	TTO	780
	Turks and Caicos Isl.	TCA	796
	Virgin Isl. (Br.)	VGB	092
	Virgin Islands (U.S.)	VIR	850
5	Brazil	BRA	076
6	Argentina	ARG	032
	Bolivia	BOL	068
	Chile	CHL	152
	Colombia	COL	170
	Ecuador	ECU	218
	Falklands Isl.	FLK	238
	French Guyana	GUF	254
	Guyana	GUY	328
	Paraguay	PRY	600
	Peru	PER	604
	Suriname	SUR	740
	Uruguay	URY	858
	Venezuela, RB	VEN	862
7	Algeria	DZA	012
	Egypt, Arab Rep.	EGY	818
	Libya	LBY	434
	Morocco	MAR	504
	Tunisia	TUN	788
	Western Sahara	ESH	732
8	Benin	BEN	204
	Burkina Faso	BFA	854
	Cameroon	CMR	120
	Cape Verde	CPV	132
	Central African Republic	CAF	140
	Chad	TCD	148

	Congo, Dem. Rep.	COD	180
	Congo, Rep.	COG	178
	Cote d'Ivoire	CIV	384
	Equatorial Guinea	GNQ	226
	Gabon	GAB	266
	Gambia, The	GMB	270
	Ghana	GHA	288
	Guinea	GIN	324
	Guinea-Bissau	GNB	624
	Liberia	LBR	430
	Mali	MLI	466
	Mauritania	MRT	478
	Niger	NER	562
	Nigeria	NGA	566
	Sao Tome and Principe	STP	678
	Senegal	SEN	686
	Sierra Leone	SLE	694
	St. Helena	SHN	654
	Togo	TGO	768
9	Burundi	BDI	108
	Comoros	COM	174
	Djibouti	DJI	262
	Eritrea	ERI	232
	Ethiopia	ETH	231
	Kenya	KEN	404
	Madagascar	MDG	450
	Mauritius	MUS	480
	Reunion	REU	638
	Rwanda	RWA	646
	Seychelles	SYC	690
	Somalia	SOM	706
	Sudan	SDN	736
	Uganda	UGA	800
10	South Africa	ZAF	710
11	Andorra	AND	020
	Austria	AUT	040
	Belgium	BEL	056
	Denmark	DNK	208
	Faeroe Islands	FRO	234
	Finland	FIN	246
	France	FRA	250
	Germany	DEU	276
	Gibraltar	GIB	292
	Greece	GRC	300
	Iceland	ISL	352
	Ireland	IRL	372
	Italy	ITA	380
	Liechtenstein	LIE	438
	Luxembourg	LUX	442
	Malta	MLT	470
	Monaco	MCO	492
	Netherlands	NLD	528
	Norway	NOR	578
	Portugal	PRT	620
	San Marino	SMR	674
	Spain	ESP	724
	Sweden	SWE	752
	Switzerland	CHE	756
	United Kingdom	GBR	826
	Vatican City State	VAT	336
12	Albania	ALB	008
	Bosnia and Herzegovina	BIH	070
	Bulgaria	BGR	100
	Croatia	HRV	191
	Cyprus	CYP	196
	Czech Republic	CZE	203
	Estonia	EST	233
	Hungary	HUN	348
	Latvia	LVA	428

	Lithuania	LTU	440
	Macedonia, FYR	MKD	807
	Poland	POL	616
	Romania	ROU	642
	Serbia and Montenegro	YUG	891
	Slovak Republic	SVK	703
	Slovenia	SVN	705
13	Turkey	TUR	792
14	Belarus	BLR	112
	Moldova	MDA	498
	Ukraine	UKR	804
15	Kazakhstan	KAZ	398
	Kyrgyz Republic	KGZ	417
	Tajikistan	TJK	762
	Turkmenistan	TKM	795
	Uzbekistan	UZB	860
16	Armenia	ARM	051
	Azerbaijan	AZE	031
	Georgia	GEO	268
	Russian Federation	RUS	643
17	Bahrain	BHR	048
	Iran, Islamic Rep.	IRN	364
	Iraq	IRQ	368
	Israel	ISR	376
	Jordan	JOR	400
	Kuwait	KWT	414
	Lebanon	LBN	422
	Oman	OMN	512
	Qatar	QAT	634
	Saudi Arabia	SAU	682
	Syrian Arab Republic	SYR	760
	United Arab Emirates	ARE	784
	Yemen, Rep.	YEM	887
18	India	IND	356
19	Korea, Dem. Rep.	PRK	408
	Korea, Rep.	KOR	410
20	China	CHN	156
	Hong Kong, China	HKG	344
	Macao, China	MAC	446
	Mongolia	MNG	496
	Taiwan	TWN	158
21	Brunei	BRN	096
	Cambodia	KHM	116
	Lao PDR	LAO	418
	Malaysia	MYS	458
	Myanmar	MMR	104
	Philippines	PHL	608
	Singapore	SGP	702
	Thailand	THA	764
	Timor-Leste	TLS	626
	Vietnam	VNM	704
22	Indonesia	IDN	360
	Papua New Guinea	PNG	598
23	Japan	JPN	392
24	American Samoa	ASM	016
	Australia	AUS	036
	Cook Isl.	COK	184
	Fiji	FJI	242
	French Polynesia	PYF	258
	Kiribati	KIR	296
	Marshall Islands	MHL	584
	Micronesia, Fed. Sts.	FSM	583
	Nauru	NRU	520
	New Caledonia	NCL	540
	New Zealand	NZL	554
	Niue	NIU	570
	Northern Mariana Islands	MNP	580
	Palau	PLW	585
	Pitcairn	PCN	612

	Samoa	WSM	882
	Solomon Islands	SLB	090
	Tokelau	TKL	772
	Tonga	TON	776
	Tuvalu	TUV	798
	Vanuatu	VUT	548
	Wallis ans Futuna Island	WLF	876
25	Afghanistan	AFG	004
	Bangladesh	BGD	050
	Bhutan	BTN	064
	Maldives	MDV	462
	Nepal	NPL	524
	Pakistan	PAK	586
	Sri Lanka	LKA	144
26	Angola	AGO	024
	Botswana	BWA	072
	Lesotho	LSO	426
	Malawi	MWI	454
	Mozambique	MOZ	508
	Namibia	NAM	516
	Swaziland	SWZ	748
	Tanzania	TZA	834
	Zambia	ZMB	894
	Zimbabwe	ZWE	716
27	Greenland	GRL	304
28	Antarctica	ATA	010

Table A 2. Additional allocations of former states given in the IEA extended balances [IEA, 2014].

TIMER region No.	IEA region
12	Former Yugoslavia
16	Former Sovjet-Union

Table A 3. TIMER regions with their conversion to GEA regions, based on proportion of area in % [Deijns, 2014; CIA; 2014].

TIMER division to regions GEA on area			
TIMER Region ID	TIMER Name	fraction of GEA Region	Corresponding GEA region
1	Canada	1	CAN
2	USA	1	USA
3	Mexico	0.095	LAC
4	Other Central America	0.035	LAC
5	Brazil	0.417	LAC
6	Other South America	0.453	LAC
7	North Africa	0.758	NAF
8	Western Africa	1	WCA
9	Eastern Africa	0.242	NAF
		1	EAF
10	South Africa	0.160	SAF
11	Western Europe	0.824	WEU
12	Central Europe	1	EEU
		0.008	FSU
13	Turkey	0.176	WEU
14	Belarus/MitigOldova/Ukraine	0.037	FSU
15	Central Asia	0.177	FSU

16	Caucasus Russian Federation	0.778	FSU
17	Middle East	1	MEE
18	India	1	IND
19	Korea	0.050	OEA
		0.023	PAS
20	China Mongolia	1	CHN
		0.650	OEA
21	South -East Asia	0.426	PAS
		0.300	OEA
22	Indonesia/Papua New Guinea	0.551	PAS
23	Japan	1	JPN
24	Australia/Oceania	1	OCN
25	Other Southern Asia	1	OSA
26	Other Southern Africa	0.840	SAF
27	Greenland	-	-
28	Antarctica	-	-

Table A 4. GEA regions and their corresponding countries [GEA, 2012]. Mexico is given as a separate region for oil resources, but is included in the Central and Latin America (LAC) region for gas.

Region ID GEA	Corresponding countries
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 MitigOldova, 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 Palestine 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)

Annex B: Unconventional oil & gas energy balances case studies

1. Unconventional oil production

Oil sands mining and extraction

Table B.1. Inputs in oil sands projects, based on Alberta oil sands project statistics [AER, 2013]. OS: oil sands, BT: bitumen, SCO, synthetic crude oil, Int HC: intermediate hydrocarbons, NP: naphta (diluent), PG: process gas (refinery gas), NG: natural gas, CK: cokes, EL: electricity. Sulphur was part of the mass balances, but, as this has no intrinsic calorific value, was left out of the allocation calculation. * In the total column electricity has been converted to primary energy with an average electricity conversion of 36%. The %-row is also based on primary energy for electricity.

	Total*	OS	BT	SCO	IHC	NP	PG	NG	CK	EL*
Production [$MJ/MJ_{bitumen}$]										
Syncrude Canada Ltd. - SYNCRUDE AURORA	**0.096**	0.058	0.000	0.002	0.000	0.000	0.000	0.049	0.000	-0.005
	% of Total	60.8%	0.0%	2.0%	0.0%	0.0%	0.0%	50.5%	0.0%	-13.2%
Shell Canada Energy - ALBIAN SANDS ENERGY INC.	**0.360**	0.222	0.000	0.000	0.000	0.006	0.000	0.134	0.000	-0.001
	% of Total	61.7%	0.0%	0.0%	0.0%	1.7%	0.0%	37.1%	0.0%	-0.5%
Shell Canada Energy - SHELL JACKPINE MINE	**0.075**	0.058	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.005
	% of Total	77.5%	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	0.0%	18.9%
Imperial Oil Resources Ventures Limited - Kearl Mine Project	**0.665**	0.390	0.000	0.004	0.000	0.015	0.000	0.198	0.000	0.021
	% of Total	58.6%	0.0%	0.5%	0.0%	2.3%	0.0%	29.8%	0.0%	8.7%
Production + upgrading [MJ/MJ_{SCO}]										
Suncor Energy Inc. - SUNCOR ENERGY OSG	**0.262**	0.365	0.119	0.000	0.000	-0.002	-0.020	0.103	-0.291	-0.004
	% of Total	139.4%	45.3%	0.0%	0.0%	-0.8%	-7.8%	39.4%	-111.2%	-4.3%
Syncrude Canada Ltd. - SYNCRUDE MILDRED LAKE	**0.387**	0.188	0.200	0.000	0.000	0.000	0.000	0.121	-0.131	0.003
	% of Total	48.7%	51.8%	0.0%	0.0%	0.0%	0.0%	31.3%	-33.9%	2.1%
Canadian Natural Resources Limited - CNRL HORIZON OIL SANDS PROJECT	**0.434**	0.447	-0.001	0.000	0.005	0.001	0.000	0.146	-0.169	0.002
	% of Total	103.0%	-0.1%	0.0%	1.0%	0.2%	0.0%	33.7%	-38.9%	1.1%

Table B.2. Inputs in the Kearl Mine project, based on the report by Esso & Imperial [Esso & ImperialOil, 2006] and Everts [2008]. NG: natural gas, DS: diesel, EL: electricity. * In the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%. The %-column is also based on primary energy for electricity.

Open Pit Mining			
Process step	**Energy input or output [$MJ/MJ_{bitumen}$]**	**% of Total**	**EC**
Utilities & infrastructure (direct electricity use)	0.003	2.4%	NG
Bulldozer transport	0.001	1.2%	DS
Mining	0.002	1.6%	NG
Truck transport	0.014	13.3%	DS
Pipeline Transport	0.001	1.0%	NG
Extraction	0.101	95.9%	NG
Generated electricity*	-0.006	-15.4%	EL
Total*	**0.106**		

Oil sands in-situ production

Table B.3. Inputs in the McKay River Expansion project, based on the report by Petro-Canada [2005] and Everts [2008]. EL: electricity, Other: lime, magnesium and soda ash (inputs for the process), NG: natural gas, NGL: natural gas liquids, BT: bitumen. * In the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%. The %-column is also based on primary energy for electricity.

In-situ SAGD			
Process step	**Energy input or output [$MJ/MJ_{bitumen}$]**	**% of Total**	**EC**
Utilities & infrastructure (electricity import)*	0.002	2.6%	EL
Supporting minerals (input + transport)	0.000	0.1%	Other
Steam production	0.252	96.9%	All
	0.182	*70.2%*	*NG*
	0.020	*7.5%*	*NGL*
	0.050	*19.2%*	*BT*
Pipeline transport	0.001	0.4%	NG
Total*	**0.260**		

Table B.4. Inputs in the Whitesands in-situ pilot project, based on the report by Orion [2003], Everts [2008] and Greaves et al. [2012]. NG: natural gas, EL: electricity. * In the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%. The %-column is also based on primary energy for electricity.

In-situ THAI			
Process step	**Energy input or output [$MJ/MJ_{bitumen}$]**	**% of Total**	**EC**
Steam production	0.013	16.6%	NG
Air compression*	0.024	82.1%	EL
Pipeline transport	0.001	1.3%	NG
Total*	**0.081**		

Bitumen and extra heavy oil upgrading

Table B.5. Inputs in bitumen and extra heavy oil upgrading, based on Alberta oil sands project statistics[AER, 2013] and the report by Petro Canada [PetroCanada, 2005] and Everts [2008]. OS: oil sands, BT: bitumen, SCO, synthetic crude oil, Int HC: intermediate hydrocarbons, NP: naphta (diluent), PG: process gas (refinery gas), NG: natural gas, CK: cokes, EL: electricity. Sulphur was part of the mass balances, but, as this has no intrinsic calorific value, was left out of the allocation calculation. * In the total column electricity has been converted to primary energy with an average electricity conversion of 36%. The %-row is also based on primary energy for electricity.

	Total	OS	BT	SCO	IHC	NP	PG	NG	CK	EL*
Upgrading [MJ/MJ$_{SCO}$]										
Nexen Energy ULC - Nexen Long Lake Project Upgrader	**0.057**	0.000	0.149	0.000	0.005	0.205	-0.492	0.085	-0.003	0.039
	% of total	0.0%	262.0%	0.0%	8.4%	359.0%	-863.0%	149.0%	-5.5%	190.0%
Shell Canada Energy - SHELL SCOTFORD UPGRADER	**0.181**	0.000	0.058	0.000	0.013	0.001	0.031	0.077	0.000	0.000
	% of total	0.0%	32.3%	0.0%	7.2%	0.5%	17.3%	42.9%	0.0%	-0.2%
Petro Canada Sturgeon Upgrader Phase I, II, III	**0.094**	0.000	0.380	0.000	0.000	0.000	-0.080	0.007	-0.190	-0.008
	% of total	0.0%	405.0%	0.0%	0.0%	0.0%	-85.3%	7.9%	-202.6%	-25.0%

Oil shale mining & retorting

Table B.6. Shale oil mining and retorting with Alberta Taciuk Processor, based on a low energy case and a high energy case by Brandt [2009]. Prelimenary operations on average require 5000 gallons of diesel, 100 tonnes of steel and 1000 tonnes of concrete. Mining in the low-case is modeled on an open-pit coalmine, mining equipment is diesel-powered [BLM, 2007]. Mining in the high-case is modeled as oil sands open-pit mining, natural gas powered (table 3.x., section x.). Crushing is diesel powered, the startup of the retorting is natural gas fired [BLM, 2007]. Retorting requires heat for the actual kerogen decomposition and electricity (for the machinery involved) is partly generated with process gases produced, and partly imported. All figures are based on an output of 4038 MJ/ tonne of raw shale for the low energy case, and 3950 MJ/tonne raw shale for the high energy case. Other details are described in the article by Brandt [2009]. Other: diesel, steel and concrete, DS: diesel, EL: electricity, NG: natural gas, KR: kerogen (shale oil). * In the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%. The %-column is also based on primary energy for electricity.

	Alberta Taciuk low			Alberta Taciuk high		
Process step	**Energy input or output [MJ/MJ$_{sco}$]**	**% of Total**	**EC**	**Energy input or output [MJ/MJ$_{sco}$]**	**% of Total**	**EC**
Prelimenary operations (grading, cement pouring, tank construction)	0.000	0.1%	Other	0.000	0.0%	Other
Mining*	0.027	13.2%	All	0.108	17.6%	NG
	0.014	*3.6%*	*DS*			
	0.013	*9.5%*	*EL*			
Transport	0.003	0.7%	DS	0.006	0.9%	DS
Crushing	0.003	0.8%	DS	0.003	0.5%	DS
Startup retort	0.005	1.4%	NG	0.006	0.9%	NG
Retorting*	0.301	78.6%	All	0.352	62.2%	All
	0.300	*77.9%*	*KR*	*0.336*	*54.9%*	*KR*
	0.001	*0.6%*	*EL*	*0.016*	*7.3%*	*EL*
Upgrading	0.019	5.0%	NG	0.108	17.6%	NG
Total*	**0.385**			**0.611**		

In-situ oil shale conversion methods

Table B.7. Shale oil in-situ retorting and production with the Shell In-situ Conversion Process, based on a low energy case and a high energy case by Brandt [2008]. Prelimenary operations on average require 5000 gallons of diesel, 100 tonnes of steel and 1000 tonnes of concrete. Electricity for pumping, the freeze wall and retorting with resistance heating is partly produced from gases co-produced in the shale oil production, partly imported. These ratios differ in the low and high energy cases. All figures are based on an output of 2632 MJ/ tonne of raw shale for the low energy case, and 2543 MJ/tonne raw shale for the high energy case. Other details are described in the article by Brandt [2008]. Other: diesel, steel and concrete input for infrastructure, DS: diesel, EL: electricity, KR: kerogen (shale oil), NG: natural gas. * In the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%. The %-column is also based on primary energy for electricity.

	Shell ICP 1 low			Shell ICP 1 high			Shell ICP 2		
Process step	Energy input or output [MJ/MJ$_{sco}$]	% of Total	EC	Energy input or output [MJ/MJ$_{sco}$]	% of Total	EC	Energy input or output [MJ/MJ$_{sco}$]	% of Total	EC
Prelimenary operations	0.000	0.1%	Other	0.000	0.1%	Other			
Drilling	0.003	0.5%	DS	0.005	0.8%	DS			
Miscellaneous	0.013	2.6%	DS	0.001	0.1%	DS			
Pumping*	0.000	0.2%	EL	0.001	0.2%	EL			
Freeze wall*	0.020	6.1%	All	0.021	9.3%	EL			
	0.013	*2.6%*	*KR*						
	0.006	*3.5%*	*EL*						
Retorting	0.438	87.3%	KR	0.382	83.2%	All	0.169	99.8%	*EL*
				0.31	*49.9%*	*KR*			
				0.074	*33.3%*	*EL*			
Remediation*	0.015	3.0%	KR	0.010	4.3%	EL			
Total*	**0.502**			**0.618**			**0.469413**		

2. Unconventional gas production figures

Shale gas production

Table B.8. Inputs in a Marcellus Shale gas development project [Aucott & Melillo, 2013]. DS: diesel, EL: electricity, Other: wastewater treatment chemicals, NG: natural gas.
[a] converted from volumes with data IPCC [2006]
[b] energy carrier type: assumption.
[c] the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%.
[d] natural gas consumption reported as 8.2% of total natural gas available at wellhead.
[e] all based on a gas production output of 3.0 Bcf per well, over the lifetime of the project [Aucott & Melillo, 2013].

Shale Gas Development			
Process step	**Energy input or output [MJ/MJ_{gas}] [e]**	**% of Total**	**EC**
Drilling rig mobilization, site prep, demobilization (Transportation) [a]	0.00002	0.02%	DS
Drilling rig mobilization, site prep, demobilization (Drill pad and road construction)	0.00004	0.05%	DS [b]
Well drilling (single, horizontal) (Transportation) [a]	0.00011	0.12%	DS [b]
Well drilling (single, horizontal) (Power engines) [c]	0.00065	0.69%	EL
Well drilling (single, horizontal) (Oil-based mud)	0.00004	0.04%	DS
Completion rig mobilization and demobilization [a]	0.00002	0.02%	DS
Well completion (single, horizontal) (Transportation) [a]	0.00012	0.13%	DS
Well completion (single, horizontal) (Fracking pump engines operation) [a]	0.00208	2.23%	DS
Well completion (single, horizontal) (Rig engines operation) [c]	0.00003	0.03%	EL
Well completion (single, horizontal) (Site reclamation)	0.00002	0.02%	DS [b]
Well completion (single, horizontal) (Transportation for site reclamation)	0.00001	0.01%	DS
Well completion (single, horizontal) (Production equipment installation, transportation)	0.00000	0.00%	DS [b]
Steel for well casing, (embodied energy)	0.00114	1.22%	Steel
Cement for well casing, (embodied energy)	0.00031	0.34%	Cement
On-site engines and similar equipment, (embodied energy) [c]	0.00031	0.34%	All
	0.00025	*0.26%*	*DS*
	0.00002	*0.07%*	*EL*
Steel (embodied energy) construction for pipelines; construction portion is mid-point of range of estimates	0.00284	3.04%	Steel
Hydrofracturing chemicals and proppant (embodied energy)	0.00130	1.39%	Chemicals
Production brine removal, transportation, 30 years	0.00035	0.37%	DS [b]
Wastewater treatment, energy consumed, mid-point of range of estimates	0.00080	0.85%	Other
Electricity used for transmission and distribution [c]	0.00114	1.22%	EL
NG consumption for compression and processing [d]	0.08200	87.86%	NG
Total [c]	**0.09333**		

Table B.9. Inputs in a Shale gas development project [Yaritani & Matsushima, 2014]. DS: diesel, EL: electricity, NG: natural gas.
[a] energy carrier type: assumption based on Marcellus shale gas [Aucott & Melillo, 2013].
[b] the 'total' figure electricity has been converted to primary energy with an average electricity conversion of 36%.
[c] energy carrier type: assumption.
[d] all based on a gas production output of 3.0 Bcf per well, over the lifetime of the project [Aucott & Melillo, 2013].

Shale Gas Development			
Process step	**Energy input or output [MJ/MJ_{gas}] [d]**	**% of Total**	**EC**
Well pad construction	0.00239	1.07%	DS [a]
Well drilling [b]	0.00344	1.55%	All
	0.00101	*1.26%*	*EL*
	0.00064	*0.29%*	*DS [a]*
Fracking water	0.00383	1.72%	DS [a]
Fracking chemicals	0.00105	0.47%	Fracking Chemicals
Fugitive emissions during well completion	0.01769	7.93%	NG
Flaring	0.00890	3.99%	NG
Lease/plant energy	0.04715	21.14%	NG [c]
Vented CO2 at plant	0.01769	7.93%	NG
Fugtive at well	0.03979	17.84%	NG
Fugitive at plant	0.02659	11.92%	NG
Workover (shale gas well)	0.01769	7.93%	NG
Transmission (compression fuel)	0.00593	2.66%	NG [a]
Fugitive transmission	0.02802	12.57%	NG
Transmission (construction of pipelines)	0.00284	1.27%	Steel
Total [b]	**0.22302**		

Table B.10. Inputs of a Shale gas production project in China [Chang et al., 2014-a, Chang et al., 2014-b]. DS: diesel, NG: natural gas.
[a] converted from volumes or mass with data from IPCC [2006]
[b] based on total diesel consumption (kg) in supplementary information [Chang et al., 2014-b].
[c] embedded energy for materials is given, energy allocation per process step is done on a mass basis [Chang et al., 2014-b].
[d] energy allocation per process step is done on a mass basis [Chang et al., 2014-b]. Only upstream CH4 allocated to diesel is left out of the balance because of possible double counting due to own research approach.
[e] all based on a gas production output of 3.0 Bcf per well, over the lifetime of the project [Aucott & Melillo, 2013].

Shale Gas Development in China			
Process step	**Energy input or output [MJ/MJ_{gas}] [e]**	**% of Total**	**EC**
Pad preparation, transportation of diesel [a]	0.00031	1.65%	All
	0.00012	*0.65%*	*DS* [b]
	0.00012	*0.63%*	*Cement* [c]
	0.00005	*0.27%*	*Sand & Gravel* [c]
	0.00001	*0.08%*	*Waterproof fabric* [c]
	0.00001	*0.03%*	*NG* [d]
Well drilling: rig power, transportation fluids & cuttings, equipment power, on site energy use	0.00809	42.69%	DS [b]
Well cementation: cement, casing, transportation [a]	0.00208	10.96%	All
	0.00001	*0.07%*	*DS* [b]
	0.00196	*10.32%*	*Steel* [c]
	0.00005	*0.27%*	*Cement* [c]
	0.00006	*0.29%*	*NG* [d]
Hydraulic fracturing, well completion, fracturing [a]	0.00282	14.89%	All
	0.00184	*9.73%*	*DS* [b]
	0.00006	*0.31%*	*Sand & Gravel* [c]
	0.00092	*4.85%*	*NG* [d]
Drilling fluids [a]	0.00565	29.81%	All
	0.00547	*28.84%*	*DS* [b]
	0.00013	*0.67%*	*CaCl2* [c]
	0.00001	*0.08%*	*Bentonite* [c]
	0.00004	*0.19%*	*Lime* [c]
	0.00001	*0.04%*	*NG* [d]
Total	**0.01896**		

Table B.11. Inputs of a Shale gas development project [Dale et al., 2013-a, Dale et al.,2013-b]. NG: natural gas, n.i.: no information available on energy carrier.
[a] based on a weighted per-well average mean gas production over the time period. These production amounts were 2.43 Bcf and 3.82 Bcf per well for the periods 2007-2010 and 2011-2012 respectively [Dale et al., 2013-b].

Shale Gas Development						
Process step	**Energy input or output $[MJ/MJ_{gas}]$ [a]**	**% of Total**	**EC**	**Energy input or output $[MJ/MJ_{gas}]$ [a]**	**% of Total**	**EC**
Pad construction (Mean)	0.00058	0.71%	n.i.	0.00018	0.22%	n.i.
Drilling (Mean)	0.00545	6.69%	n.i.	0.00393	4.82%	n.i.
Completion (Mean)	0.00084	1.03%	n.i.	0.00051	0.62%	n.i.
Waste Management (Mean)	0.00135	1.65%	n.i.	0.00042	0.51%	n.i.
Leakage	0.01300	15.94%	NG	0.01300	16.59%	NG
Compression	0.04833	59.27%	NG	0.04833	61.68%	NG
Processing	0.01200	14.71%	NG	0.01200	15.31%	NG
Total	**0.08155**			**0.07837**		