Comparison of the life cycle greenhouse gas emissions of shale gas, conventional fuels and renewable alternatives from a Dutch perspective.

A thesis to attain a master's degree in the discipline of Energy Science

Project Commissioned by Energie Beheer Nederland B.V.

by Atse Louwen

Front cover image sources:

"Marcellus Shale Gas Drilling Rig at Night" by Rocking Granny Fine Art.
http://www.rockinggrannyfineart.com/the_gold_paintings.htm

Logo EBN
http://www.ebn.nl

Logo Universiteit Utrecht
http://www.uu.nl/NL/Informatie/medewerkers/huisstijl/Huisstijlelementen/logo/Pages/default.aspx

Colophon

Title:	**Comparison of Life Cycle Greenhouse Gas Emissions of Shale Gas with Conventional Fuels and Renewable Alternatives.** *Comparing a possible new fossil fuel with commonly used energy sources in the Netherlands*

Author:	Atse Louwen	
	Address: Donkerstraat 19 3511KB Utrecht The Netherlands	
	T: +31 (0)6 53 968 967 E: atse.louwen@gmail.com	
Host institute:	Energie Beheer Nederland B.V. Moreelsepark 48 3511EP Utrecht The Netherlands	
Host supervisor:	Maarten Jan Brolsma E: maarten-jan.brolsma@ebn.nl	(daily supervisor)
University supervisors:	Ernst Worrell E: e.worrell@uu.nl	(general supervisor)
	Evert Nieuwlaar E: e.nieuwlaar@uu.nl	(LCA supervisor; second reader)
University:	Utrecht University Department of Science, Technology and Society Budapestlaan 6 3584CD Utrecht The Netherlands	

Date of publication:	Friday, 02 September 2011

Acknowledgements

I would like to thank Maarten Jan Brolsma and Ernst Worrell specifically, and the staff of EBN in general for all the supervision and support during the process of writing this master's thesis.

I would like to thank Evert Nieuwlaar for his input on LCA and for helping me with SimaPro and the Ecoinvent database documentation.

I would like to think Ruud Schulte for helping me with Que$tor.

I would like to thank everybody who has showed in interest to and/or has given feedback on my research and presentations.

Executive summary

This report, commissioned by Energie Beheer Nederland B.V., analyzes the life cycle greenhouse gas emissions of shale gas production and use as a fuel for electricity production, and compares shale gas with conventional natural gas, coal, wind energy, and nuclear energy in terms of life cycle greenhouse gas emissions. The aim of this study is to first of all rank shale gas in the current spectrum of electricity production routes, and assess the major factors determining the GHG footprint of shale gas. With this information both Energie Beheer Nederland and national policy makers gain insight on the effect of the use of shale gas in the near future.

Shale gas production has seen an enormous increase in the United States in the last years, has allowed the U.S. to become more energy independent, and has drastically increased the amount of natural gas reserves. This increase in production is primarily possible due to two advances in gas well drilling and completion: horizontal drilling and hydraulic fracturing. Especially the latter has been the subject of some environmental concerns. During hydraulic fracturing, large amounts of water, mixed with sand and chemicals in a total concentration of up to 2% are injected into the well at high pressure. The high pressure forms fractures in the shale rock through which the natural gas can escape. It is argued that due to hydraulic fracturing, a number of concerns arise. One of those concerns is that shale gas production has a dramatically increased greenhouse gas footprint due to the increased effort required to extract it and increased methane leakage from wells.

This study shows that overall, shale gas does have an increased GHG footprint compared to conventional natural gas, both when looking at production only and at the use as an electricity fuel. Overall, when used to produce electricity, the GHG emissions of shale gas are about 4.4% higher at 485 gCO_2-eq/kWh compared to conventional natural gas at 465 gCO_2-eq/kWh. Compared to coal fired electricity however, emissions of electricity produced with shale gas are much lower at only about 50% of coal emissions. A comparison with LNG imported from Algeria shows that compared to LNG, shale gas emissions are much lower, about 3% lower when comparing a fuel mix of 90% conventional natural gas and 10% of shale gas or LNG.

A concern with shale gas production lies with the uncertainty of the amount of methane released after hydraulic fracturing, when the water used for this purpose flows back out of the well. In the few available studies on this specific topic, a large range of methane emissions in this phase of the lifecycle is reported. If a worst case scenario is assumed, overall GHG emissions of shale gas powered electricity are about 15% higher compared to conventional gas fired electricity. Future research should establish clear figures for methane emissions after hydraulic fracturing to reduce this uncertainty.

Another factor that has a large influence in the overall result for the shale gas lifecycle is the total lifetime production per shale gas well. Data for shale gas wells in the United States show a large variation, partly due to the fact that shale gas in the United States is produced from a variety of locations. For the Netherlands, such production estimates are not yet available. To present more specific emissions figures for the Netherlands, this research should be updated with Dutch production estimates.

This study also confirms that both nuclear and wind powered electricity have much lower GHG emission per unit of electricity compared to the fossil fuel fired electricity plants. However, partly due to the specific origin of Dutch uranium, nuclear emissions are slightly higher compared to other European studies. Furthermore there is a large variation in literature data on emissions in various phases in the nuclear lifecycle. Offshore wind electricity has the lowest emissions of this study, at 11.2 gCO_2-eq/kWh.

Nederlandse samenvatting

In opdracht van Energie Beheer Nederland B.V. is een onderzoek uitgevoerd naar de emissies van broeikasgassen over de gehele levenscyclus van schalie gas. Hierbij is gekeken naar zowel de productie van schaliegas, als het gebruik ervan in Nederlandse elektriciteitscentrales. Het primaire doel van dit onderzoek was om de broeikasgas emissies van schaliegas te plaatsen binnen het spectrum van energiedragers dat momenteel in Nederland wordt gebruikt. Hierbij is schaliegas vergeleken met de bestaande energiebronnen conventioneel aardgas, kolen, wind- en kernenergie.

Schaliegas wordt al enige tijd in grote hoeveelheden geproduceerd in de V.S., waar schaliegas ervoor gezorgd heeft dat de ondergrondse gasreserves enorm zijn toegenomen, waardoor de afhankelijkheid van gas uit het buitenland is afgenomen. Schaliegas zit opgesloten in een gesteentelaag die van zichzelf niet voldoende poreus is om het gas te laten ontsnappen. Om deze reden wordt de gesteentelaag gebroken door onder hoge druk een mengsel van water, zand, en chemicaliën (tot een concentratie van maximaal 2%) in het gesteente te pompen. Hierbij ontstaan scheuren in het gesteente waardoor het gas kan ontsnappen en worden afgevangen. Dit proces van breken wordt "Hydraulic Fracturing" genoemd. Sinds de opkomst van schaliegas productie door middel van *hydraulic fracturing* is er bezorgdheid gerezen over de mogelijke schadelijke effecten van deze methode voor aardgas productie. Allereerst zijn er zorgen over mogelijke vervuiling van het grondwater door het gebruik van de chemicaliën, maar er zijn ook onderzoekers die stellen dat bij de productie van schaliegas, met name na *hydraulic fracturing*, grote hoeveelheden broeikasgassen vrijkomen.

Uit dit onderzoek blijkt dat het gebruik van schaliegas, gezien over de gehele levenscyclus, inderdaad verhoogde concentraties broeikasgassen uitstoot. Wanneer gekeken wordt naar de toepassing van schaliegas in elektriciteitsproductie, is deze toename zeer gering te noemen. Ten opzichte van conventioneel aardgas neemt de uitstoot van broeikasgassen met 4.4% toe per kilowatt uur geproduceerde elektriciteit. Hiermee kent schaliegas na conventioneel aardgas de laagste emissies van broeikasgassen van de fossiele brandstoffen. In vergelijking met kolen-elektriciteit zijn de emissies per kilowatt uur elektriciteit ongeveer 50% lager. In vergelijking met elektriciteit opgewekt met gebruik van vloeibaar getransporteerd aardgas (LNG) of Russisch aardgas zijn de emissies van schaliegas eveneens lager. Uit het onderzoek blijkt voorts dat het grootste deel van het verschil tussen conventioneel en schaliegas wordt verklaard door het feit dat schaliegas putten een veel lagere productie hebben over hun levensduur dan conventionele aardgas putten. Hierdoor nemen de benodigdheden voor schaliegasproductie relatief (per hoeveelheid aardgas) sterk toe. Wanneer echter wordt gekeken naar een levenscyclus met toepassing van aardgas in elektriciteitsproductie, wordt duidelijk dat het overgrote deel van de emissies (meer dan 90%) vrijkomt bij de verbranding van het gas in de elektriciteitscentrale.

Een niet onbelangrijke onzekerheid in de broeikasgas emissies ligt in de fase na *hydraulic fracturing*, waarbij het water dat voor dit proces wordt gebruikt terugstroomt uit de put. De hoeveelheid methaan die hierbij vrijkomt varieert sterk in de weinige studies die zich hierop richten. Wanneer de hoogste tot nu toe gerapporteerde waarde wordt gebruikt in berekeningen, zijn de emissies van elektriciteit geproduceerd met schaliegas ongeveer 15% hoger vergeleken met elektriciteit geproduceerd met conventioneel aardgas. Verder onderzoek zou zich moeten richten op dit onderdeel van de levenscyclus om deze onzekerheid te verkleinen. De emissies van schaliegas zijn in dit geval echter nog steeds lager vergeleken met LNG, Russisch gas, en kolen. Een andere factor die grote invloed kan hebben op het eindresultaat is de totale productie van een schaliegas put. Data voor schaliegas putten in de V.S. laat een grote variatie zien. Nederlandse productieramingen zijn nog niet beschikbaar. Toekomstig onderzoek zou Nederlandse productiecijfers moeten gebruiken om de onzekerheid weg te nemen.

De andere bestudeerde elektriciteitsvormen kennen substantieel lagere emissies per kilowatt uur elektriciteit. De laagste emissies worden uitgestoten door windenergie, gevolgd op zekere afstand door kernenergie. Met name voor kernenergie is er in de literatuur echter wel een zeer grote spreiding in data die de emissies in verschillende fases van de levenscyclus beschrijft, vooral richting hogere waarden.

Table of contents

Glossary/Abbreviations

CHP: Combined Heat and Power

CNG: Conventional natural gas. Normally, CNG refers to Compressed natural gas, in this study CNG always refers to Conventional Natural Gas.

EBN: Energie Beheer Nederland B.V.

Exergy: The exergy of a source of energy (for instance heat or electricity) is a measure of the amount of physical work this source can perform. For further information see Appendix A.1.

CO_2-eq/kWh: Carbon dioxide equivalent emissions per kilowatt hour. Based on the Fourth Assessment Report by the International Panel on Climate Change, the global warming effect of all the different GHG emissions have been converted mathematically to CO_2 equivalent emissions.

GHG: Greenhouse gas

GWP: Global Warming Potential

HF: Hydraulic fracturing

IOA: Input Output Analysis.

ISL: In situ leach

ISO: International Organization for Standardization

LCA: Life Cycle Assessment

LHV: Lower heating value. In all combustion reactions of hydrocarbons, water is formed. This water is vaporised during the combustion reaction. This vaporisation requires a certain amount of energy that can thus not be used to produce electricity. The lower heating value assumes the vaporisation heat is lost and cannot be recovered.

LNG: Liquefied natural gas

NPP: Nuclear power plant

PCA: Process Chain Analysis. An approach in LCA that looks bottom-up at a life cycle and analyses all the involved processes and the inputs and outputs per process.

Proppant: Granular material, commonly sand, that is used in hydraulic fracturing to keep the fractures open that are formed under high pressure

PV: Photo Voltaic: converting light into electricity by capturing photons.

PWR: Pressurized water reactor

SWU: Separative Work Unit

List of tables

List of figures

1. Introduction

With traditional natural gas reservoirs of the Netherlands nearing depletion and with no viable renewable alternatives presently operational, the Dutch state in general and Dutch gas company Energie Beheer Nederland B.V. (EBN) specifically are looking into exploring and exploiting new, unconventional sources of natural gas. Estimates made in 2009 put the Dutch natural gas reserves at almost 1400 billion cubic meters on January 1st 2010, and the annual production at over 70 billion cubic meters (Ministerie van Economische Zaken, 2010). With an annual production of over 70 billion cubic meters, these reserves would run out in less than 20 years assuming constant production at 2009 levels.

One of the new, unconventional sources could be shale gas, a type of gas which has been mined outside of the Netherlands on a large scale for the last few decades, most notably in the United States. Aside from traditional natural gas fields nearing depletion, expectations are that the demand for natural gas will increase globally. Although in the OECD the demand for coal and oil is expected to drop, natural gas is the only traditional fossil fuel with an expected increase between 2008 and 2035; unconventional gas such as shale gas is expected to meet 35% of this future demand for natural gas (IEA, 2010d). The International Energy Agency has recently even stated that "gas is set to play a key role in meeting the world's energy demand" (IEA, 2010d). Outside the OECD, most notably in China, the demand for natural gas is also expected to grow.

Preliminary estimates state that shale gas reservoirs in The Netherlands could hold up to several times the amount of gas originally contained in the Groningen gas field. Apart from the uncertainty in the actual amounts of shale gas, it is also yet undetermined what the environmental performance is (in terms of greenhouse gas emissions) of shale gas compared to other types of energy carriers, considering a full life cycle and different types of application. In order to address these uncertainties, a study needs to be conducted to assess the environmental performance of shale gas, e.g. the (energy and material) requirements and associated emissions for production of shale gas, as well as the CO_2 equivalent emissions of this unconventional fuel connected with other phases in its' full life cycle. Comparisons with the same parameters for traditional and renewable energy sources will determine the relative CO_2 equivalent emissions of shale gas compared to traditional fuels.

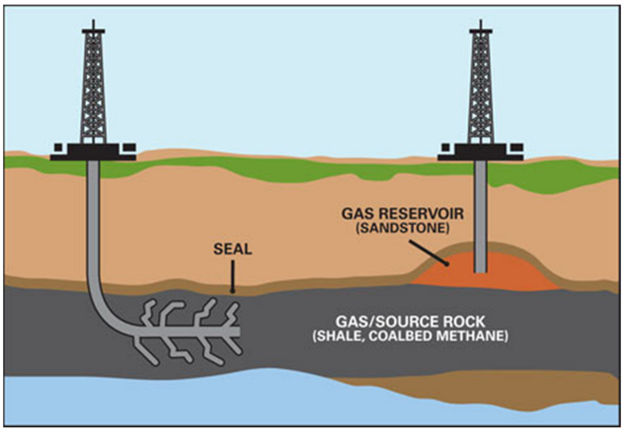


Figure 1.1: Schematic representation of the differences between conventional and unconventional natural gas production. Source: EST, 2011

Shale gas extraction is more complicated than conventional natural gas (CNG) extraction, as the gas is still trapped in the source rock. As this source rock has a low permeability, shale gas is extracted using hydraulic fracturing (HF). Water, with a selection of chemicals and proppant (e.g. sand), is injected into the well at high pressure to fracture the source rock to allow the gas to be extracted. Previously, shale gas fields featured several vertical wells; however more recently, due to advances in drilling technology, more productive horizontal wells are drilled. The effort required to extract shale gas are high compared to traditional gas, but the consequence of this increased effort in terms of added greenhouse gas (GHG) emissions is not yet established. The differences between conventional gas and shale gas production are illustrated in Figure 1.1. Preliminary investigations indicate that life cycle GHG emissions of shale gas might be several times higher than those of conventional gas and even coal (Howarth, 2010). This preliminary assessment finds that the majority of GHG emissions of shale gas production is caused by methane leakage; however, methane leakage appears to be considered only for gas and not for coal. Other research in the study of methane leakage from natural gas production and transportation systems indicate that leakage in Russia is at approximately 1.4% of total throughput (Lelieveld et al., 2005), and this figure is 1.5±0.5% in the United States, and is low enough both in Russia and in the US for natural gas to be preferable above coal and oil in terms of life cycle GHG emissions (Lelieveld et al., 2005).

This study is to be conducted from a Dutch position as it is commissioned by EBN, and EBN is 100% state owned. Therefore, this study will focus on Dutch applications of natural gas and will compare alternative energy carriers as they are used in The Netherlands. The main current applications of natural gas in The Netherlands are, in order of the amount of TJ used (IEA, 2010c):

1. Transformation (combined heat and power and electricity)
2. Residential use (cooking and space heating)
3. Services
4. Industrial use

For each application studied, shale gas will be compared with a range of alternatives such as coal, biomass, wind, solar (PV), nuclear, where applicable for each specific application and as applied in The Netherlands.

Alternatives for shale gas in The Netherlands, when applied to produce electricity include (traditional) natural gas, coal, wind, nuclear and biomass, in order of the amount of gigawatt hour of electricity produced with each energy source in 2008 (IEA, 2010b). Recent years have furthermore seen increasing attention for "green gas", biogas or synthetically produced gas that is processed to sufficient quality to be used in the national gas grid. However, the production capacity of biogas is currently very low compared to the total demand (GasTerra, 2011) and significant replacement of natural gas with green gas is expected not to occur on the short term but rather on mid to long term (>5 years) (Platform Nieuw Gas, 2007. Because of this time constraint, green gas is not studied here.

In space heating, the only direct alternative for shale gas would be natural gas, as the vast majority of Dutch households use natural gas for space heating. This limits the scope of the analysis for space heating specifically to the upstream processes (all processes before the use phase), as this is where the differences occur. In cooking, natural gas is the most commonly used energy carrier, followed by electricity.

Life Cycle Assessment studies commonly cover a broad range of environmental impact categories, including global warming potential, human toxicity, soil and water eutrophication[a], and others. As this study focuses on a reasonably broad range of alternatives, environmental impact assessment will be restricted to the global warming potential. This will include several GHGs but focuses on carbon dioxide and methane. As Huijbregts et al., 2006 have stated, the fossil Cumulative Energy Demand largely determines the environmental impact in several categories of air pollutant emissions, and especially shows strong correlation with global warming potential (GWP). This would mean that by investigating only the impact category GWP, an indication is obtained for the impact in different environmental impact categories. However, the cumulative energy demand is much less useful in determining other environmental impacts such as environmental or human toxicity (Huijbregts et al., 2006), impacts that are often connected with shale gas production. Important negative impacts of the different alternatives not covered by the GWP will be mentioned qualitatively. Important issues that have been connected to shale gas development are mostly problems related with HF. There are concerns that the use of chemicals in the fracturing fluid could lead to ground (drinking) water pollution and toxicity for humans and environment. Although important, these impacts are not assessed in this study as this study focuses on GHG emissions.

---

[a]Eutrophication is the disturbance of the nutrient balance in an ecosystem through addition of nutrient substances from fertilizers or sewage. It can result in among others algal blooms, excessive plant growth and (local) extinction of plant and animal species.

This study aims to assess amount of GHG emissions released in the full life cycle of shale gas compared to currently used conventional and renewable alternatives. This will provide decision makers with relevant information and assist in formulating national energy policy aimed at reducing GHG emissions. However, since water pollution and toxicity issues are not studied here, further study needs to be conducted to inform policy makers about these environmental impacts of shale gas development.

The main research question of this study is: ***What are the life cycle GHG emissions of shale gas compared to traditional fossil fuel alternatives and renewable alternatives in two applications in The Netherlands and over their full life cycle?*** This question will be answered with the aid of a set of sub-questions:

A) What are the main possible applications of shale gas in The Netherlands?

B) For each application as found in (A), what are the most commonly used alternatives in The Netherlands?

C) What are the energy and material requirements for the extraction of shale gas in The Netherlands?[b]

D) What are these requirements for each of the alternatives found in (B)?

E) What is the environmental impact in terms of GHG emissions of the applications and alternatives as found in (A) and (B) and based on the requirements found in (C) and (D)?

F) When combining and reviewing the results of (C) through (E), per application, in what stages of the life cycle do the biggest differences occur between shale gas and the alternatives?

[b]As there are as of yet no operational shale gas wells in The Netherlands, this part will be an estimate based on US experience in shale gas production.

2. Methodology

This study will be a LCA with a focus on GHG emissions alone. The study will be based on the methodology as detailed in Baumann & Tillman, 2004 and Guinée, 2002.

As electricity production and direct use are the main uses of natural gas in The Netherlands (IEA, 2010c), the study will consist of two parts:

1. Comparison of electricity generation options and;
2. Comparison of natural gas production alternatives

Natural gas in The Netherlands is generally processed to "Groningen Equivalent (Geq)[c]" quality.

The alternatives will be compared with the help of the 'functional unit' a term common in LCA studies. The functional unit allows for a direct comparison of the alternatives mentioned above on the basis of their main function (for this study: electricity and direct gas use), and connects the output of one 'unit of function' to the associated environmental impacts. For electricity, this functional unit will be "one kilowatt-hour of electricity produced in The Netherlands and as delivered to the grid". For the direct use of gas, the main function of the product system is to supply an amount of gas. The functional unit here will be "one megajoule of natural gas (Geq) produced and supplied in The Netherlands."

This study will focus on CO_2 and CH_4 emissions. As this study is meant to compare total emissions of each alternative, and not CO_2 and CH_4 separately, methane emissions will be converted into CO_2 equivalent emissions using a conversion factor of 25 kg CO_2 eq./kg CH_4. This factor describes the global warming potential of methane for a period of one hundred years. The value is taken from Solomon, 2007.

This study will consider (Weisser, 2007):

1. *Upstream* emissions (mining, extraction, processing, transportation and construction of all facilities),
2. *Direct* emissions (power plant operation, combustion) and
3. *Downstream* emissions (decommissioning of all installations, waste treatment and disposal, including infrastructure).

For the direct use of natural gas however, only upstream processes will be considered. Downstream is a term that is often used (especially in the oil and gas industry) to refer to processes that occur beyond the wellhead of a natural gas well, e.g. processing and sales of the natural gas. To clarify, in this study downstream refers to processes occurring after the use phase of each energy source.

Geographical limitations

Geographically, the scope of this study is limited to The Netherlands, with the assumption that all processes take place in The Netherlands. Exceptions here are the mining, processing and transportation of coal and nuclear fuel, and the production of wind turbines. As this study aims on finding the total life cycle emissions of various alternatives, and not the emissions in The Netherlands

[c]Groningen equivalent has an energy content of 35.17 MJ/m^3 (HHV) at a temperature of 0°C and a pressure of 1013 mbar. The actual energy content of a produced m^3 will vary but for accounting purposes all gas produced in the Netherlands is reported in Groningen equivalent units.

only, these emissions will be included, based on country specific data. Figure 2.1 shows an overview of all the countries included in this study.

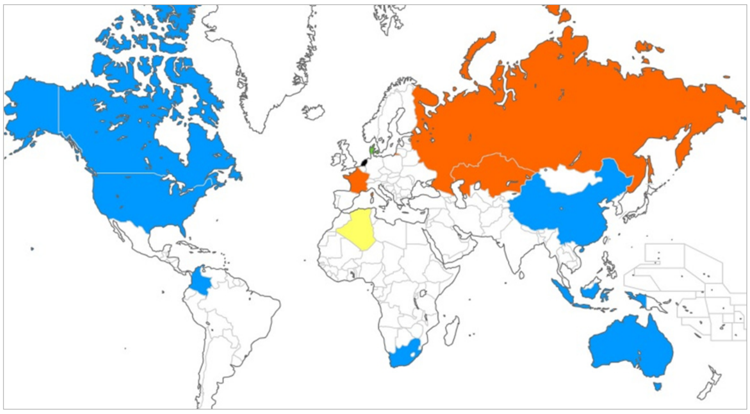


Figure 2.1: Overview of all the foreign countries included in this study due to foreign occurring processes. Colours indicate the specific system the country is included in. Blue = Coal; Orange = Nuclear; Yellow = Conventional Natural Gas; Green = Wind. Shale gas is assumed to include only the Netherlands (coloured black).

Temporal limitations

Temporally the study is limited by the lifetime of the infrastructure and power plants and all activities are assumed to take place in present time (with present-day technology).

Process chain analysis (PCA) vs. input-output analysis (IOA)

This study will combine process chain analysis (PCA) and input-output analysis (IOA). PCA focuses on the analysis of the complete chain of processes in the life cycle of a product (Guinée, 2002; Baumann & Tillman, 2004), and is a complete bottom-up analysis of the life cycle of a product. However, PCA is very data- and time-intensive and therefore it is often suggested that PCA is supplemented with IOA in a hybrid analysis (Weisser, 2007). IOA is a method to analyse the effect of economic activity based on sectoral energy intensity (or carbon intensity) data. IOA will be employed in this study mainly to estimate the emissions released in 2^{nd} and higher order activities. With IOA, not only the direct emissions, but also the emissions released throughout the whole economy as a consequence of the production of required material and the input of labour are included. A downside of IOA is a greater uncertainty in the results, as the sectoral data is an average and this ignores the fact that one product out of a sector can be more energy intensive than another from the same sector. Therefore, IOA will only be used for processes that do not have a large effect on total life cycle emissions.

Data sources and modelling of life cycles

As mentioned in the previous section, the better part of this study is based on PCA. As PCA is an elaborate process, the modelling of the various life cycles will be performed with the aid of SimaPro (PRé Consultants, 2006), a software tool used globally to model life cycles and assess life cycle environmental impacts. SimaPro is one of the most used LCA software tools and has great respect from the European LCA community (Rice et al., 1997). Integrated with SimaPro is a comprehensive database from Swiss life cycle inventory centre Ecoinvent (Ecoinvent Centre, 2007). This database offers one of the most comprehensive selections of life cycle inventories globally. As this study focuses on the Dutch situation data will have to be adapted (if possible) to suit the specific situation studied here, in terms of both location and time. The specific adaptations to the EcoInvent database will be detailed per alternative in Chapter 3. Other sources of data include environmental reports of companies involved in the various life cycles, and previously conducted peer reviewed LCA's.

SimaPro includes various methods to characterize emissions and other life cycle related occurrences (such as fossil fuel consumption or various forms of toxicity). As this study focuses on the impact of the life cycles on the climate, the method employed here is based on the Fourth Assessment Report by the International Panel on Climate Change (Solomon, 2007), which details the substances contributing to (anthropogenic) global warming and assesses each substance's contribution to radiative forcing[d]. The overall result is represented in carbon dioxide equivalent emissions per unit of energy (kWh_e or MJ_{th}).

2.1. Electricity production systems

In total, five different electricity generation systems were compared:

- Shale gas-fired
- Conventional natural gas-fired
- Coal-fired
- Nuclear
- Wind power (onshore and offshore)

The alternatives aside from shale gas were selected because they are the most common means of electricity generation in The Netherlands (IEA, 2010b). Biomass would be among these alternatives, but is somewhat of an exception. There is almost no electricity produced with "biomass-only" power plants (there are currently 3 biomass power plants operational with a total combined capacity of just over 60MW). Instead, almost all biomass used to produce electricity, is co-fired in coal power plants (Seebregts & Volkers, 2005). As the biomass comes from a large variety of sources sometimes unknown (Seebregts & Volkers, 2005), co-firing of biomass is not included in this study. Table 2.1 gives an overview of the different generation options including their percentages in the total electricity mix. Process diagrams are included below per power generation option.

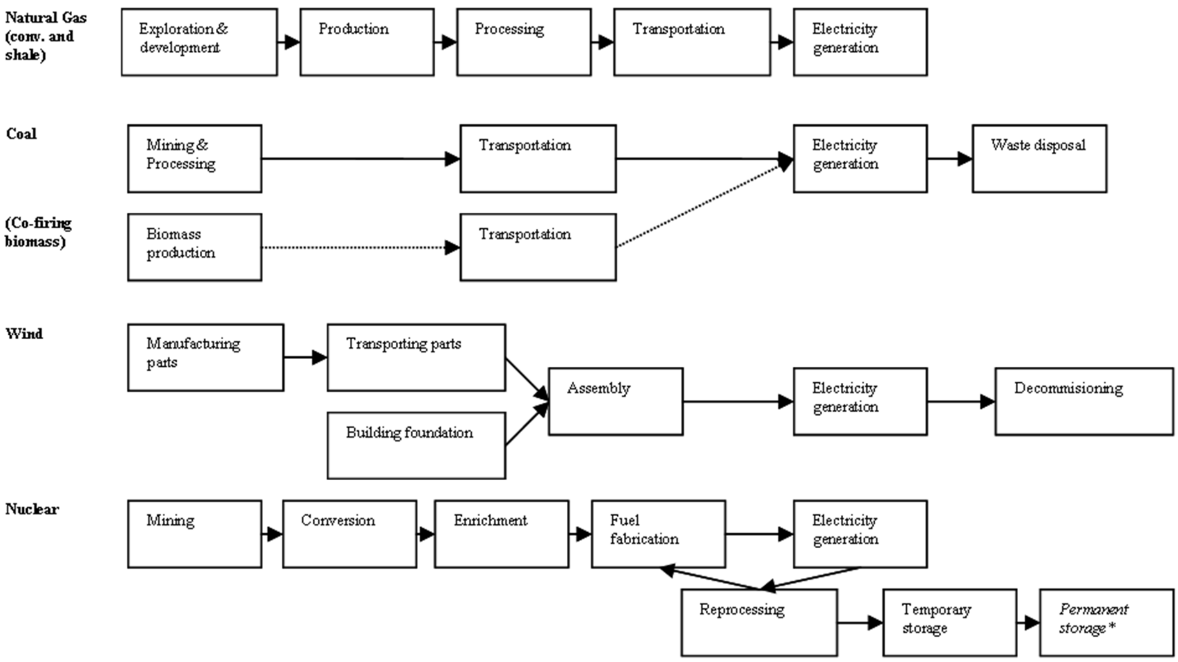


Figure 2.2: Overview of electricity generation systems studied. Adapted from Hondo et al., 2005 with data from Dones et al., 2005; Sovacool, 2008 and Voorspools et al., 2000. **Permanent storage is included in this diagram but not the analysis.*

[d]Radiative forcing is defined by the IPCC as the "measure of the influence a factor has in altering the incoming and outgoing energy in the Earth-atmosphere system and is an index of the importance of the factor as a potential climate change mechanism" (Pachauri et al., 2007). This allows for calculation of the global warming potential of various substances relative to the global warming potential of carbon dioxide. The global warming potential of substances other than CO_2 is reported in CO_2-equivalent units (gram of CO_2-equivalent per gram of substance).

As mentioned before in the introduction, shale gas and other unconventional gas resources are expected to supply a large percentage of future energy demand increases. Unconventional gas is also mentioned as a fuel that could replace other fuels such as coal in order to decrease GHG emissions. In this context, shale gas could be replacing average coal fired power plants, or it could be used in newly built power plants, thus preventing the construction and use of newly built coal fired power plants. Therefore, this study will assess average and marginal emissions for the different electricity production options, based on average (existing) technology and marginal (newly built) technology.

The functional unit for the first part of this study, covering electricity production is defined as "one kilowatt-hour of electricity produced in The Netherlands and as delivered to the grid". This functional unit allows for a comparison of the GHG emissions of the various alternatives in grams of CO_2-equivalent per kWh_e. It follows implicitly from the definition of the functional unit that transportation and distribution losses for electricity are not considered. They are assumed to be equal for all energy systems, and thus are assumed to not influence the overall results. Total lifecycle emissions will be calculated as follows (adapted from Hondo, 2005) per alternative generation option:

$$LC\ GHG\ emis = \frac{\sum[(E_{u,i} + E_{d,i} + E_{ds,i}) * GWP_i]}{Q} \qquad (1)$$

Where E_u are the upstream emissions, E_d are the direct emissions and E_{ds} are the downstream emissions, *GWP* is the global warming potential conversion factor to CO_2-equivalent emissions (use 1 for CO_2), and Q is the total electricity output of the considered generation option over its lifetime. The subscript *i* indicates the substance emitted (CO_2 or CH_4). Transmission losses over the electricity grid are not considered, as these are assumed to be equal for all alternative generation options studied.

The figures for E_u, E_d, and E_{ds} will themselves also be a sum of all the emissions in each respective phase. As an illustration, E_u will be comprised of emissions released by construction activities (energy requirement) of extraction infrastructure, but also of emissions released during the production of the required material. Input data for the energy and material requirements for up- and downstream processes will be taken largely from the EcoInvent database, a Swiss database commonly used for life cycle analyses.

Table 2.1: Electricity production alternatives in The Netherlands. NG_{conv}-fired = power plant fuelled by natural gas from conventional sources. Percentages based on IEA (2010c). Average efficiencies from Seebregts & Volkers, 2005. *Nuclear efficiency is assumed to be 33% and describes the relation between thermal output of reactor and electrical output.

Generation option	Percentage of total electricity production NL (2008)	Average efficiency of Dutch plants (LHV[e])
NGconv-fired	59%	46%
Coal-fired	25%	39%
Wind power	4.0%	-
Nuclear	3.9%	33%*

The formula is a simplified illustration of the actual calculations. To account for differences in lifetimes, and differences in well productivity (one shale gas well does not deliver as much gas as a conventional well), the upstream emissions will be calculated as total emissions per amount (kg, MJ, m^3) of fuel. These upstream emissions will then be included in the total life-cycle GHG emissions by calculating the amount of fuel needed based on the figure for Q in equation (1) and the overall efficiency of the respective generation

[e] LHV = Lower heating value. In all combustion reactions of hydrocarbons, water is formed. This water is vapourised during the combustion reaction. This vapourisation requires a certain amount of energy that can thus not be used to produce electricity. The lower heating value assumes the vapourisation heat is lost and cannot be recovered.

option. As illustrated in Figure 2.2, each fuel is produced in a very different way. Therefore, the calculations will be different and thus, equation (1) will be expanded to fit each electricity generation option.

2.1.1. Natural Gas (conventional)

As The Netherlands produces more natural gas than it uses (CBS, 2010), all natural gas studied is assumed to have been produced in The Netherlands. The power plants studied are assumed to be typical Dutch natural gas plants. As several Dutch natural gas plants co-generate heat and power, the electric efficiency (LHV basis) of these power plants will be calculated on the basis of useful energy output based on exergetic[f] properties of electricity and heat (see Appendix A.1). In literature, a variety of approaches is used to allocate emissions in co-generation situations, without there being a clear consensus on the most suitable approach. Graus & Worrell, 2010 show that the method used can strongly influence the overall result. Therefore, a variety of methods is used in the sensitivity analysis of this study (see Chapter 5) to assess the variation in the overall result. The exergetic approach is chosen as the main method here since it assesses the efficiency of power generation on the basis of physical usefulness of the outputs.

Methane leakage during production, transportation and storage of natural gas is considered. The CNG is assumed to be produced in a mix of offshore and onshore gas fields such as the "Groningen" gas field. Differences in up- and downstream emissions for onshore and offshore gas production will be accounted for by incorporating the percentage of gas produced at the respective location. Energy and material requirements for extraction and infrastructure are estimated with the help of EBN's experience is this matter and comparison with data available in scientific literature and the EcoInvent database. The natural gas cycle consists of exploration, extraction (including infrastructure, transmission (pipe systems, energy requirement), processing, combustion (construction of plant, decommissioning), and waste management. The natural gas used is assumed to be processed to "Groningen Equivalent" quality. The upstream emissions (as mentioned in equation 1) for producing natural gas will be calculated with the following equation:

$$E_{u,i} = \left(\frac{E_e + E_{dev} + E_{prod} + E_{proc} + E_{trans}}{total\ production} \right) \cdot \frac{Q}{\eta} \qquad (2)$$

Where E_e are the emissions related with exploration (test drilling), E_{dev} are the emissions related to development activities (drilling and casing of the well) and manufacturing of materials; E_{prod} are the emissions released during the production phase; E_{proc} are the emissions related to processing the natural gas (including manufacturing and construction of processing equipment); and E_{trans} are the emissions related with transmission of gas (losses, material and energy requirements including construction of pipelines). All these factors will be assessed per well. Therefore, *total production* is the total amount of fuel produced from one well. This amount is based on Dutch averages (conventional gas) and American realized averages and Dutch estimates (shale gas). The part of the formula between parentheses will then give the GHG emissions per MJ of natural gas. The second part of equation (2) gives the amount of fuel needed for each generation option, by dividing the total output of fuel with the overall efficiency of the respective power plant. Off course, both Q and "*total production*" should be of the same unit, MJ in this case. The upstream emissions for the other electricity generation options will be calculated similarly, of course taking into account the differences in the life-cycle layout.

Import of Liquefied natural gas

According to the EBN roadmap concerning shale gas, it is expected to start production in 2015. By this time, it is expected that the share of Liquefied Natural Gas (LNG) in the Dutch natural gas mix will have grown to about 10%. Recently, various plans for LNG

[f] The exergy of a system is defined as the maximum amount of useful work it can perform when coming into equilibrium with its surroundings. Hot water can perform less work per MJ of heat than electricity can per MJ, and is therefore less 'useful' or of lower 'quality' as a source of energy. For further explanation and calculations, see Appendix A.1.

terminals in the Netherlands have been cancelled, but one terminal is still under construction currently, with a throughput capacity of 12 BCM/year, scheduled for completion in 2011 ((Gasunie, 2011). When at full capacity, this terminal could supply about 10% of the total throughput of gas through the Dutch gas grid (Gasunie, 2011). To assess the difference in emissions between a Dutch gas mix and a gas mix with LNG, a separate scenario was investigated with an assumed LNG share of 10%. LNG is produced in various countries, however, in this analysis; it is assumed all LNG originates in Algeria. Emissions figures will be based on the calculated emissions for gas produced abroad, and will be expanded with liquefaction and transportation emissions data from Ecoinvent Centre, 2007. It is assumed that other imports of CNG will not increase significantly before 2015.

Import of Russian gas via long distance pipelines

Another possible source of natural gas is Russia, being the largest producer of natural gas globally that already exports large amounts of natural gas to Europe. Furthermore, a pipeline from Russia to Germany is currently under construction. Considering the ambitions of the Dutch government to become a major gas hub for western Europe, it is not unlikely that Russian gas will be imported to the Netherlands in the future. To analyse the influence of this scenario on GHG emissions, data from the Ecoinvent database was analysed and included in the results for conventional natural gas. As with the LNG scenario, a 10% share of total supply was assumed to come from Russia.

Onshore vs. offshore gas production

In the Netherlands, first years of gas production solely took place onshore, however, in 1970 offshore production commenced (Ministerie van Economische Zaken, 2010). The ratio between onshore and offshore production has fluctuated much since 1970, but the last years it has been somewhat stable at about 70% onshore, 30% offshore; based on produced volumes. The requirements for offshore gas production are significantly higher compared with onshore activities. This is primarily caused by two factors:

1. The drilling/production locations are more distant, increasing transportation and pipeline length and;
2. Operations all take place on and under water, requiring heavy machinery, floating drilling rigs (jack up rigs) and boats, barges and helicopters, and drilling takes place at varying water depths. Also, the production equipment needs to be supported on large steel platforms.

2.1.2. Natural gas (shale)

Shale gas is assumed to be produced in The Netherlands; therefore transportation from abroad is not included in this analysis. However, as there is as of yet no experience with the extraction of shale gas in The Netherlands, energy and material requirements, with their associated GHG emissions, are estimated based on U.S. experience in shale gas extraction. Data will be tailored as much as possible to the Dutch situation with the help of scientists and engineers working for EBN or her partners, based on physical characteristics of Dutch shale gas fields. As it will be assumed that shale gas is processed to Groningen Equivalent quality, it is also assumed that no differences occur between shale and conventional gas during the use phase and downstream processes. Additional steps compared to CNG include increased drilling, usage of HF fluids (including waste management of fracturing fluids) and the usage of pumps as well as increased processing requirements of the extracted gas. It is not yet know what the exact composition of Dutch shale gas is, but it could differ significantly from traditional natural gas in terms of composition (and consequently, caloric value). To address this issue, several shale gas scenarios will be investigated in section 5.2, with low, medium, and high caloric value shale gas, where the values will be based on U.S. shale gas values and Dutch estimates. The main results will however be based on the assumption that the composition and calorific value of shale gas is equal to that of CNG produced in the Netherlands.

Transportation and storage requirements in the Dutch national gas grid (including leakage rates) are assumed to be the same as for CNG produced onshore. Part of the production equipment is however installed per well or per group of wells, this will be accounted for. As mentioned in the introduction, there are several practices for extracting shale gas. Previously, drilling multiple, vertical completions was common. However, more recently, advances have been made in horizontal drilling, increasing per well lifetime production and reducing the amount of drilling operations needed. It will be assumed in this study that the state of the art practices will be used in future Dutch shale gas extraction.

2.1.3. Coal

Coal is not domestically produced in The Netherlands. The production system for coal electricity therefore includes mining of coal in other countries and transport via ocean freighters to The Netherlands. From VDKi, 2009 it has been established that The Netherlands imported coal from South Africa, Colombia, The United States, Australia, Indonesia and a very small amount from several other countries.

Table 2.2: Hard coal imports to The Netherlands per country of origin. Data presented are general figures of hard coal imports and not specific for electricity production only.

Country of origin*	Amount (kton)*	Percentage of total
South Africa	8307	38,1%
Colombia	6100	28,0%
United States	2976	13,6%
Australia	2383	10,9%
Indonesia	1669	7,7%
Canada	307	1,4%
China	68	0,3%
Poland	1	0,0%
Total	21811	100%

*Data from VDKi, 2009. Percentages were calculated based on this data.

Table 2.2 gives an overview of all countries mentioned as exporting to The Netherlands in (VDKi, 2009). This table shows that in total almost 22 Mton of coal are imported, however, only about 13 Mton are used domestically (Centraal Bureau voor de Statistiek, 2010; IEA, 2010b). The data reported are general import figures for hard coal and are not specific for the mix used in Dutch power plants. However, as Dutch energy companies are not required to supply information on the origin of the coal used in their power plants, it will be assumed that all power plants use a mix of coal equivalent to the import percentages mentioned in

Canada, China and Poland are excluded from this mix because of the very low percentage of imports from these countries in the total mix.

Coal power plants are assumed to be typical Dutch coal fired power plants, with co-firing of biomass. The complete coal cycle studied here consist of exploration, extraction (including infrastructure, transportation (train, ocean freighter), processing, combustion (including construction and decommissioning of plant and flue gas treatment) and waste management. Data is based on Dutch practice for the use phase and Dutch internal transportation. Data for upstream processes is based on international data. Methane leakage during production of coal is considered. Methane leakage rates from coal mining vary per country. To address this, methane leakage will be investigated per country and included in the result based on the import percentages in Table 2.2.

2.1.4. Wind power

The wind power process chain is slightly less elaborate than process chains of other power generation options discussed here. It basically consists of production of the wind turbine and tower parts, construction of the foundation, transportation of the parts to the construction location, assembly (including connection to the grid), operation, maintenance and decommissioning of the installation.

An important factor with wind power is its intermittent production of electricity. For total life cycle electricity production, average load factors will be assumed throughout the whole lifetime based on yearly electricity production figures from Dutch wind turbines compared to the total installed capacity Centraal Bureau voor de Statistiek, 2011. Especially at high penetration rates of wind energy, the intermittent character of wind power also necessitates a backup electricity generation capacity in case there is no wind or too strong wind. This backup capacity and its possible environmental impacts are not considered in this study.

Most of the currently installed wind power capacity is installed onshore. However, plans have been made and are being made to strongly increase the offshore capacity in The Netherlands. There are substantial differences between onshore and offshore wind turbines. Offshore wind turbines are often of high capacity (>2 MW) compared to onshore turbines (around 0.6-0.8 MW). However, in the Netherlands, several onshore turbines are of typical "offshore capacity". Furthermore, offshore wind turbines need more construction work and operation and maintenance (because of among others higher corrosion due to salt water) and have a lower lifetime than onshore turbines (Jungbluth et al., 2005). Offshore wind turbines however have a higher capacity factor compared with onshore turbines (Jungbluth et al., 2005; Pehnt et al., 2008). Due to these differences between on- and offshore turbines, these technologies will be assessed independently of each other, however, the study will be based on similar wind turbines (both of 3.0MW capacity), because of the fact mentioned earlier that typical "offshore capacity" turbines are being installed onshore.

2.1.5. Nuclear

Currently there is only one nuclear power plant (NPP) operational in The Netherlands, the Borssele nuclear power plant. This NPP has been fuelled by a variety of fuel sources in the past, such as re-enriched depleted uranium, recycled uranium fuel rods and ex-military high grade uranium. In the last years however, uranium is imported from uranium mines in Kazakhstan and the rods are recycled (EPZ, 2010b). Radioactive waste is stored near the power plant in temporary storage (100 years) mixed with glass and sealed in stainless steel barrels. The nuclear fuel cycle is more complex than any other fuel studied here. It generally consists of (Dones, 2005; Hondo, 2005; Sovacool, 2008):

- Mining and milling uranium ore
- Conversion (producing UF_6)
- Enrichment (via gaseous diffusion or centrifugation)
- Fabrication of fuel rods or pellets
- Electricity generation
- Fuel processing and conditioning
- Short term and permanent storage

Most of the processes are connected by transportation. In the Dutch case, fuel is recycled after use in electricity generation. This adds another step, of reprocessing the fuel after, electricity generation. The complete process chain is illustrated in Figure 2.2.

As no precise information is available about the fuel consumption and efficiency of the Borssele NPP, it is assumed that the plant operates at 33% efficiency.

2.2. Direct use of natural gas (conventional and shale)

In the second part of this study, the direct use of natural gas is studied. In this part, shale gas will be compared to natural gas. As it is assumed that after production of 'Groningen Equivalent' gas, there is no difference between shale gas and natural gas, in this part only upstream processes (e.g. before the use phase) will be considered. Aside from this, the methodology for analysing the emissions of the direct use of natural gas will be equal to that of the electricity generation options.

In electricity generation, there is currently a wide variety of generation options, each powered by a different type of fuel. Direct use of natural gas includes residential use (cooking and heating) and industrial use (ammonia production and use in furnaces). This study is aimed to assess shale gas performance compared to alternatives, instead of for instance comparing various heating or cooking options. Therefore, for the direct application of natural gas, shale gas will only be compared to conventional natural gas. As with the analysis of electricity systems, green gas is not included here for the same reasons (see section 2.1.1)

Because the downstream processes and use phase do not result in differences between traditional natural gas and gas from other sources (assuming that all produced gas is processed to have the same 'Groningen Equivalent' composition), the analysis of this application will focus mainly on upstream processes. As mentioned in section 2.1.2, shale gas could have a significantly different composition compared to conventional natural gas. Increased processing requirements (or lower calorific "end user value") will be incorporated into this study. Decommissioning of use phase equipment will not be analysed. However, decommissioning of extraction facilities and infrastructure will be included in the analysis.

3. Material and energy requirements

3.1. Natural Gas (Conventional)

Since the discovery of the Groningen gas field, The Netherlands has been one of the largest producers of natural gas in Europe. Other producers in Europe include Russia, the largest producer in the world, and Norway and the UK, amongst others. The high supply of natural gas in the Netherlands has led to the construction of a vast network of gas transmission pipes covering the majority of the country, and with connections to neighbouring countries. This has allowed The Netherlands to become a gas exporter, and it has fuelled ambitions in the Dutch government to have the Netherlands become a major "gas hub" for Western Europe[g]. However, to maintain or increase the export of natural gas, considering the decline of production from Dutch gas fields, import or production from unconventional fields has to increase significantly. Currently, a small import share in the Netherlands comes from Norway and the UK; however, with the completion of the Nord Stream transmission system and LNG terminals in the Rotterdam port, supply from other countries becomes available to the Netherlands. A shift in the supply mix could significantly alter the GHG emission levels from Dutch gas fired power plants, as for instance, the Russian gas transmission network is characterized by much higher methane leakage rates then the Dutch or Norwegian networks (Lelieveld et al., 2005; Ecoinvent Centre, 2007; Gasunie, 2010b). Because of these developments, this section will analyse both the current gas mix and technologies, but will also analyse the GHG emissions from the estimated future gas mix and technologies.

3.1.1. Conventional Natural Gas – Upstream processes

Exploitation of a gas field is generally preceded by a phase in which geological and geophysical research is conducted to determine the likely location of gas fields and the best locations to start drilling. After this preparatory phase, the work in the field can start with exploratory drilling to assess if the formation is actually where it should be and if it the gas field is productive enough at the location to be economical. A drilling pad and a road leading to the location will be constructed, and drilling can commence at the optimal location. During and after drilling, several types of well casing are installed. After the well is completed, it is cleaned up, and tested. The next phase is production, the extraction of natural gas, which is processed partly onsite and partly offsite, during transmission to the end user.

3.1.1.1. Road and pad construction

After the right spot for development of a well is identified, a pad will be constructed there and a road leading up to the pad will be put in place. The pad is generally about 0.2 ha for a conventional natural gas well (Ecoinvent Centre, 2007). The construction of road and pad requires transportation of materials and earth moving vehicles. The main input of energy in this case is in the form of diesel for these machines. Including with the access road and the area used to treat drilling waste, about 90 square meters of land are transformed (with above mentioned equipment) per meter of well drilled (Ecoinvent Centre, 2007). In a recent study to assess the environmental impacts of shale gas production, Wood et al., 2011 summarized the findings of a New York State study from 2009 on the oil and gas industry. The number of truck visits connected to a typical U.S. well operation was estimated. In this case, the estimate was based on a multi-well pad with six wells. The number of truck visits is given in Table 3.1.

[g]See: http://www.rijksoverheid.nl/documenten-en-publicaties/publicaties-pb51/economic-impact-of-the-dutch-gas-hub-strategy-on-the-netherlands.html

Table 3.1: Estimation of the truck visits connected with a typical drilling operation				
Purpose	**Per well**		**Per pad**	
	Low	**High**	**Low**	**High**
Drilling pad and road construction equipment			10	45
Drilling rig			30	30
Drilling fluid and materials	25	50	150	300
Drilling equipment	25	50	150	300
Completion rig			15	15
Completion fluid and materials	10	20	60	120
Completion equipment	5	5	30	30
Total			445	840

3.1.1.2. Exploratory drilling

Eventually, exploratory drilling will commence. The success rate for exploration wells in the Netherlands is approaching 70% and has been steadily increasing the last thirty years, while the average find per drill has been slightly decreasing in the period 2000 -2010, from about 1.4 BCM[h] to about 1.2 BCM, or about 1.6 BCM when correcting for exploration (Energie Beheer Nederland B.V., 2010). If the exploratory drilling is successful, the well is prepared for production of natural gas. If unsuccessful, the bore hole is plugged and the well is abandoned.

3.1.1.3. (Vertical) drilling and casing of the well

Drilling, be it exploratory or specifically for the completion of a production well, is generally done with the help of diesel engines, with engine power varying according to the drilling depth required. Emissions of this stage are caused by transportation movement of drilling equipment, and the consumption of fuel during drilling. Wood et al., 2011 estimated that drilling requires about 19.16 L of diesel per meter drilled. With an average depth of about 3000m, this would mean a total consumption for drilling of 57480 L of diesel. However, this figure only includes drilling and seems to be a large underestimation for the overall use of diesel. In environmental reports NAM notes that their diesel consumption is strongly connected to the amount of drilling performed, and average diesel consumption for all drilling activities in 2006 (both onshore and offshore) amounts to 384 l diesel/m drilled (NAM, 2007). The Ecoinvent database uses figures of 250l diesel/m drilled for onshore, and 500 l/m drilled for offshore drilling, but notes that there is a large variability in literature (Ecoinvent Centre, 2007). The drilling operation also requires several materials, most notably large amounts of steel and cement. An estimate of the material requirements for a typical drilling operation is summarized in Table 3.2.

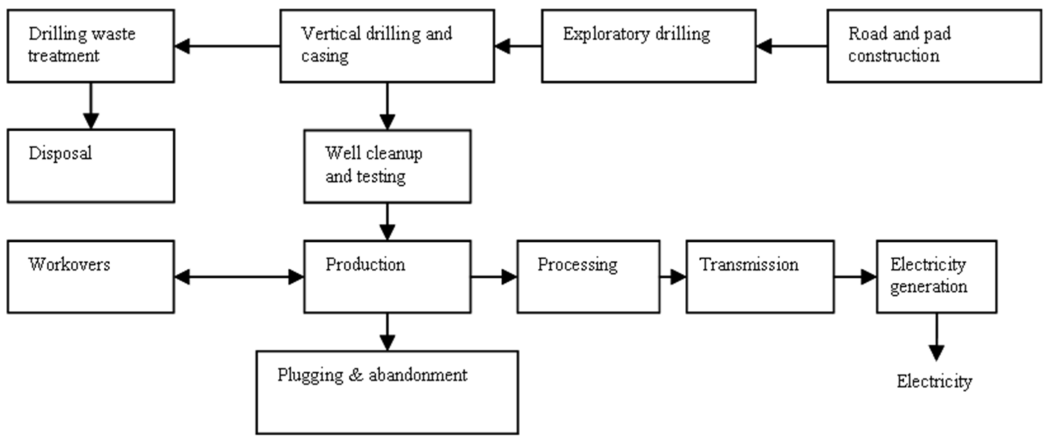


Figure 3.1: Detailed process diagram of the conventional natural gas electricity generation system. From Ecoinvent Centre, 2007; GWPC & ALL Consulting, 2009.

[h] Bcm = billion cubic meters or 10^9 m^3.

These data were taken from Que$tor, a tool primarily designed for the evaluation of costs related to the development of a gas field. This data was compared with environmental reports of NAM and the EcoInvent database (NAM, 2002; Ecoinvent Centre, 2007). Figures for both onshore and offshore operation are presented.

Table 3.2: Overview of the material and energy requirements for a typical gas drilling operation, both onshore and offshore. Data is taken from Que$tor, NAM, 2002; Ecoinvent Centre, 2007.

Description	Onshore required amount (per meter drilled)	Offshore required amount (per meter drilled)
Steel	210 kg	210 kg
Cement	57 kg [NAM] 200 kg [EcoInvent]	200 kg
Diesel (drilling, transportation, generators)	384 l [NAM] 250 l [EcoInvent]	384 l [NAM] 500 l [EcoInvent]
Weightening agents	79 kg	79 kg
Mineral oil	42 kg	42 kg

3.1.1.4. Well cleanup and testing

After the well is completed it is cleaned up (drilling mud flushed) and the production rate and other characteristics of the well are tested. At this point, if there is no equipment yet placed to capture the gas coming out of the well, it must be flared (New York State, 2009). In itself, this step is not material or energy intensive; emissions are largely associated with flaring and/or venting of natural gas and pumping of water. When procedures are finished, production can commence.

3.1.1.5. Production and transmission

After produced from the wellhead, the gas is led through pipes to a processing facility where undesired compounds are removed (CO_2, hydrocarbons except CH_4, moisture) and where nitrogen is added if needed to get the heating value down to Groningen Equivalent for domestic use (Swigchem et al., 2005). After this, the gas is pressurized and fed into transmission pipes leading to the central gas transmission grid. From here it is either distributed to power plants or to domestic or industrial supply grids. High caloric gas can be sent straight to electricity generation plants without the need for N_2 addition (Swigchem et al., 2005).

The energy requirements for these processes in the production and transportation stage of the gas cycle are dependent on gas composition and average about 0.4MJ/Nm^3[i] for compression, treatment and flaring and venting, and about 0.12MJ/Nm^3 for transportation, including addition of N_2 (Swigchem et al., 2005). These figures represent energy use in various forms. Without addition of N_2, transportation energy use (mostly in the form of natural gas) is estimated to be about 0.07-0.18 MJ/m^3 transported (Pleizier et al., 2011). More specified figures for production are given in Table 3.3, which gives an overview of the energy and material inputs of the "Nederlandse Aardolie Maatschappij" a joint venture of Shell and ExxonMobil that produces about 75% of Dutch natural gas. The figures are based on environmental reports (NAM, 2007). In Table 3.4, figures are given for the energy and material consumption during transmission, which are based on financial and environmental reports as well, in this case from "Gasunie" the Dutch company that is responsible for all gas transport in the Netherlands (Gasunie, 2010a; Gasunie, 2010b).

Table 3.3: Summary of energy inputs for the production of natural gas in the Netherlands, including (exploration) drilling, excluding infrastructure. Source: NAM, 2007. *Source: NAM, 2002.

Description	Amount per m^3 of natural gas produced	Main use
Natural gas own use	0.165 MJ	Compressors
Electricity	0.015 kWh	Compressors (mainly old fields)

[i] Nm^3 is a "normal cubic meter" and is the amount of natural gas that occupies 1 m^3 at 0 °C and a pressure of 1013 mbar.

Table 3.4: Summary of material and energy inputs for transmission of natural gas in the Netherlands. Source: Gasunie, 2010b		
Description	**Amount per m^3 of transported gas**	**Used for**
Diesel	$8.74*10^{-8}$ L	Backup generators
Methanol	$1.19*10^{-9}$ L	Antifreeze and dewatering of transmission installations and pipes
Lubricants	$5.36*10^{-7}$ L	Lubrication of compressors, engines and turbines
Glycol	$4.05*10^{-8}$ L	Antifreeze in cooling and heating installations
Odorant	$4.52*10^{-6}$ kg	Safety (detect leaks by smell)
Nitrogen	$1.41*10^{-2}$ kg	Reduce heating value per m^3 (for domestic use)
Natural gas	$1.56*10^{-3}$ m^3	Turbines and engines; heating
Electricity	$3.10*10^{-3}$ kWh	Compressors, nitrogen production

Methane leakage

During production and transmission, methane is vented and flared and released through leaks in the production and transmissions system. There are varying reports on the amount of methane released via leakage, ranging from 1.5% (Lelieveld et al., 2005) for the United States to 10% of the volume produced for Russia (Lelieveld et al., 2005) although more recent estimates for Russia seem to indicate much lower figures comparable to those for the U.S., namely 1.0-2.5% (Lelieveld et al., 2005). Figures for the Netherlands were however based on environmental reports from companies in the natural gas production and transmission industry (NAM, 2007; Gasunie, 2010b). Methane release during production is reported to be 0.024% average for the years 2003-2007 (NAM, 2007) while methane emissions in transportation are reported to be only 0.009% of transported volume (Gasunie, 2010b). The latter appear to have a decreasing trend in the years observed but this can largely be attributed to the inclusion of German emission figures from 2008 onwards since the Dutch gas transmission net was expanded with a German part. When analysed separately, the emissions for the German part of the net are lower to those of the Dutch net.

3.1.1.6. LNG import

As mentioned before, the first Dutch LNG terminal is scheduled for completion in 2011. The capacity of this terminal is sufficient to supply about 10% of the annual throughput of the Dutch gas grid. LNG is in essence the same fuel as CNG, but differences occur in the transportation stages. At the country of origin, in this study assumed to be Algeria, the gas is liquefied by cooling it to -162 °C and is loaded onto specialized LNG transport ships. At the arrival terminal, the LNG is unloaded and heated, to evaporate the liquid gas and to allow it to be transported in gas pipelines. The energy and material requirements and the resulting GHG emissions were taking directly from the Ecoinvent database (Ecoinvent Centre, 2007).

The emissions specific to LNG are released mainly because of three factors: liquefaction, transport via ship and evaporation. Especially liquefaction is an energy intensive process, consuming about 5.8 MJ of natural gas per Nm^3 of gas transported. Transportation is carried out via ocean freighters, burning about 0.35 MJ of natural gas per Nm^3 transported (over a set distance of 500 nautical miles) releasing about 21 grams of CO_2. During evaporation at the arrival terminal, the gas is evaporated by heating it, this is often done with sea water but consumes a small amount of natural gas (0.56 MJ/Nm^3), but more importantly, releases about 26 gCO_2/Nm^3. During both liquefaction and evaporation, about 0.3 grams of methane are released per Nm^3 of handled gas.

3.1.1.7. Import of Russian natural gas via long distance pipelines

Another alternative supply scenario was investigated based on Ecoinvent data (Ecoinvent Centre, 2007). For this scenario it was assumed that 10% of the Dutch natural gas supply is produced in Russia and transported to the Netherlands via long-distance pipelines. Mainly because of the large distances the natural gas from Russia needs to be transported, energy requirements and methane leakage during transportation is much higher compared to gas transportation in the Netherlands. Methane emissions during transportation account for the main fraction of total emissions followed by the energy input during transportation. Other emissions are released by the production of the gas (including well drilling and completion).

3.1.2. Natural Gas – Electricity generation

About 60% of the Dutch domestic electricity is produced with natural gas, in a variety of plant types (section 2.1). Most of the Dutch natural gas electricity plants combine the production of electricity and heat, increasing the electrical efficiency when allocating fuel use to heat production (allocation of all fuel inputs to electricity reduces the electrical efficiency with CHP[j] plants (Seebregts & Volkers, 2005). Newer natural gas plants have both a gas and a steam turbine, improving efficiency. The average efficiency of Dutch natural gas plants is in the order of 60%, when allocating fuel inputs on the basis of total energy output (MWh_e + MWh_{th}). However, the heat output is considered as less useful, or of lower quality than the electricity output, based on exergy[k]. When considering this quality factor, the average efficiency of all Dutch gas fired power plants is in the order of 43-45% (LHV basis) for the years 2001-2004 (Seebregts & Volkers, 2005). Based on more recent data, the efficiency was calculated to be similar, at 44% (LHV basis) (IEA, 2010b; IEA, 2010c). Power plant design and construction requirements are taken from Ecoinvent Centre, 2007. These include decommissioning requirements.

[j]CHP = Combined Heat and Power, a technology where residual heat is not disposed directly but rather used in industrial processes (high temperature) or for domestic heating (medium to low temperatures).

[k]The exergy of a system is defined as the maximum amount of useful work it can perform when coming into equilibrium with its surroundings. Hot water can perform less work per MJ of heat than electricity can per MJ, and is therefore less ‘useful’ or of lower ‘quality’ as a source of energy. For further explanation and calculations, see Appendix A.1.

3.2. Shale Gas

The production of (electricity from) shale gas is in many aspects very similar to that of conventional natural gas. The main differences occur upstream, because of an increased effort required (increased drilling, hydraulic fracturing) to extract the gas and a lower production per well. Some conventional wells are also hydraulically fractured and horizontally completed, however, this is not typical for conventional wells but it is an absolute requirement for economical shale gas extraction (Wood et al., 2011). The shale gas electricity production system is illustrated in Figure 3.2.

3.2.1. Shale gas – upstream processes.

As mentioned before, the processes for shale gas production are similar to those for production of conventional natural gas. From steps 1 to 4 (Table 3.5), the processes are essentially the same. The energy requirements and associated emissions of each process can differ though. The processes and differences with conventional gas production processes are summarized in Table 3.5. This section aims to clarify the differences between conventional and shale gas.

As can be seen in Figure 3.2 and Table 3.5, there are a number of processes that are in some way different for shale gas when compared to conventional natural gas. Furthermore, since the drilling pad needs to accommodate extra equipment and materials for hydraulic fracturing, the pad is often bigger. On the other hand, it is becoming more common to drill multiple wells from one drilling pad (GWPC & ALL Consulting, 2009; Wood et al., 2011) reducing the amount of drilling pad area required per well. Another difference occurs because of increased drilling activity, resulting in an increased amount of drilling waste. This requires additional waste treatment and disposal.

There are varying reports on shale gas composition coming from the United States, where some find significant differences with

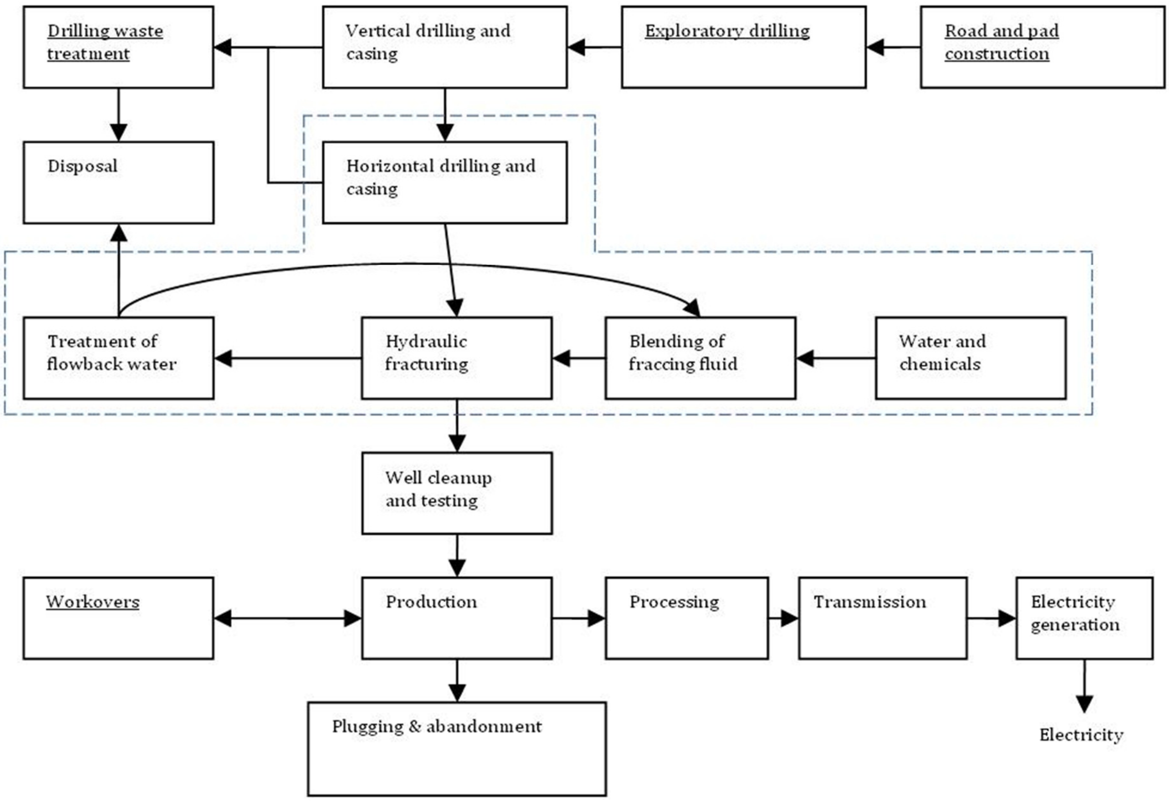


Figure 3.2: Detailed process diagram of the shale gas electricity generation system. Main differences with the conventional gas system described in section 3.1 are indicated in the blue dashed box. Processes that occur in both systems, but with different requirements and/or outputs are indicated with underlined text.

conventional gas, for instance relatively high "wetness[I]" and from varying CO_2 content across multiple shale plays (Vidas & Hugman, 2008) but also reports of "dry[I]" gas with the same varying CO_2 content (Arthur et al., 2008). As mentioned in section 3.1.1, the energy requirement for gas processing depends on the composition of the gas. Therefore, a range of shale gas compositions is investigated to assess the impact on the overall emissions of the shale gas life-cycle.

Apart from the absolute increased efforts per well, shale gas wells are generally much less productive compared to conventional gas wells (USGS, 1995 in Wood et al., 2011), leading to a large relative increase in emissions per produced MJ of natural gas. There is no accurate publicly available data on lifetime production per well, estimates are being reported in the low end of 24 million m^3/well in Barnett shale wells (Berman, 2009 in Herber & De Jager, 2010) and in higher ranges of 11 – 70 million m^3/well (Wagman, 2006 in Wood et al., 2011) to up to 104 million m^3/well (New York State, 2009 in Wood et al., 2011). Operators estimate lifetime production to average 62 – 93 million m^3/well in Barnett shale wells (Berman, 2009). Dutch estimates are not yet available. As field sizes decrease, the relative influence of infrastructure (from well to production equipment and transportation pipelines) increases. A good proxy for shale gas emissions would therefore be the emissions from smaller conventional gas fields. However, data on the emissions of these smaller conventional fields is not yet available, as smaller fields are only beginning to be exploited in the Netherlands. As production from smaller fields increases, emissions data from organisations like NAM should better reflect emissions from smaller fields. A large part of the emissions is however corrected for smaller field in the model used here, because inputs like production equipment and well drilling and completion are already corrected for field size.

Table 3.5: Processes involved in shale gas production. Differences with conventional gas production are indicated.

Step no.	Process	Difference with conventional gas
1	Road and pad construction	Multiple wells per pad because of horizontal drilling
2	Vertical drilling and casing	-
3	Horizontal drilling and casing	Conventional wells are typically only vertical (increased drilling meters)
4	Drilling waste treatment	Increased amount of waste due to increased drilling
3b-4b	Delivery of water and chemicals	Shale specific
5a	Blending of frac fluid	Shale specific
5b	Hydraulic fracturing	Shale specific
5	Treatment of waste water	Shale specific
5c	Well cleanup and testing	-
6	Production	Lower production per well
7	Workovers	More workovers/lifetime
7a	Plugging and abandonment	
7b	Processing	Assumed similar
8	Transmission	Assumed similar

3.2.1.1. Hydraulic fracturing

When examining process diagrams, differences between shale gas and conventional gas production are mostly related to hydraulic fracturing. After the horizontal drilling is complete and the well casing and tubing is in place, shale gas fields are fractured. To do this, first, the well casing and tubing is perforated. Perforation starts at the end of the well, after which the first fracturing is performed. This process is repeated from the bottom to the top of the shale section at 90-150 meter intervals. The amount of these stages is determined by the horizontal length of the well. For instance, a well that extends laterally for 1.2 km could count up to 8 to 13 fracturing stages (Wood et al., 2011).

[I]Wetness or dryness here does not refer to the amount of water produced in a well, but refers to the prevalence of heavier hydrocarbons than methane in the gas. Wet gas has a high and dry gas has a low concentration of heavier hydrocarbons.

Each HF stage is performed in multiple sub stages and uses a large amount of water with up to 2%, but typically 0.5% of chemical additives (GWPC & ALL Consulting, 2009). Amounts of fluid used in a typical Marcellus Shale[m] gas well vary from about 19 to 380m^3 per fracturing sub stage, and the chemical additives also vary from one stage to another (GWPC & ALL Consulting, 2009). In total, for one fracturing stage, about 2200 m^3 of fluid is used, in addition to about 200,000 tons of proppant[n] (GWPC & ALL Consulting, 2009), although ranges are being reported of 1,100-2,200 m^3 of fluid per HF stage, or 9,000-29,000 m^3 per well (Wood et al., 2011). By volume, the amount of chemicals used per well will be up to 180-580 m^3 per well.

The exact composition of the fracturing fluid varies from well to well, depending on well parameters and from sub stage to sub stage, because each stage has a different function (GWPC & ALL Consulting, 2009; Wood et al., 2011). After the last HF stage, about 15 to 80% of injected water flows back, which is processed for either disposal or re-use (US EPA, 2010). After the flow back stops, the well can be cleaned up and tested.

The pressure used with hydraulic fracturing ranges from 345-690 bar (Wood et al., 2011). In the United States, it is common that not only the fracturing chemicals, but also the fracturing water is brought to the drill site with trucks. However, taking in to account the dense population of the Netherlands, it is assumed that the water is brought to the site via pipelines, and only the fracturing chemicals and proppant are brought to the site with trucks. In Table 3.6, the number of truck visits associated with HF is presented (Wood et al., 2011). These have been corrected for the pipeline transport of water as mentioned earlier.

At the well pad, the chemicals, fracturing fluid, and fracturing proppant are blended together, and pumped into the well at high pressure. This task is commonly performed by diesel engines, consuming about 110,000 litres of diesel per well (New York State, 2009). However, lighter fuels or electricity could be used to reduce the emissions of this stage (Wood et al., 2011).

Table 3.6: Overview of the amount of truck visits associated with one hydraulic fracturing operation. Data from Wood et al., 2011 and adapted for pipeline transport of water. Again, it is assumed each pad contains six wells. Chemical transport requirements were estimated based on volume and water transport requirements as given in Wood et al., 2011.

Purpose	Per well		Per pad	
	Low	High	Low	High
Hydraulic fracture equipment	25	33	150	200
Hydraulic fracture proppant	20	25	120	150
Hydraulic fracture chemicals	8	12	48	72

The processes that take place after hydraulic fracturing are again very similar to those of the conventional natural gas system. An exception exists with the need to perform workovers of the shale gas wells. Workovers, or (more specifically for hydraulic fracturing) refractures, increase the productivity of a well, but also increase the energy input (and thus emissions output) per well by 50%, assuming half of all wells are refractured (Wood et al., 2011). Although workovers are sometimes also required for conventional natural gas wells (NAM, 2007), shale gas wells require more workovers relative to their lifetime.

Methane leakage

With its global warming potential of 25 gCO_2-eq/gCH_4, methane can contribute much to the overall emissions of any energy system even with relatively small emissions on a mass basis. For shale gas especially, methane emissions are the subject of some doubt and controversy in literature. As of yet, there have been few studies that assess methane emission figures from shale gas wells specifically. Those that have, indicate higher emission figures compared to conventional gas wells. In any case, it is well known that the water

[m] The Marcellus Shale is a shale formation in the Northeastern United States that contains significant quantities of natural gas and spans six state (GWPC & ALL Consulting, 2009).

[n] Proppant is a granular material (commonly sand) injected with the water to prevent the created fractures from closing.

flowing back out of shale wells after HF operations contains relatively large amounts of methane, as operators themselves are trying to more efficiently capture the methane from this flow back water. Howarth et al., 2011 state that during flow back, on average, about 1.6% of the total production from a well is released to the atmosphere. However, there is controversy concerning the quality of this research (Jackson et al., 2011). Measurements were performed by others and data and methods of these measurements are not publicly available or verifiable. The study by Howarth et al. also relates the methane emissions from shale gas well completions to the overall production. It is however arguable if methane emissions from a well completion increase when the lifetime production of said well increases. Furthermore, an earlier study reports methane emissions from shale gas wells to range from $28*10^3$-$6.8*10^5$ m^3 per well completion, with a median of $1.4*10^5$ m^3 (Armendariz, 2009). In the study by Armendariz, several Barnett Shale gas producers were interviewed and reported that on average about $1.4*10^5$ m^3 of methane is released per well completion. Another report indicates that methane was found in concentrations above the normal average in ground water in areas near active shale gas wells (Osborn et al., 2011). However, Jackson et al., 2011 state that there is a lack of clear estimates on GHG emissions from shale gas production. In this study, methane emissions figures for shale gas are assumed to be similar to those for conventional wells; however, in section 5.2, scenarios with higher methane emissions from flow back water are investigated to test the influence on the overall result. This will include a "worst case scenario" analysis based on the data by Howarth et al.

3.2.2. Shale Gas - Electricity Generation

As mentioned in section 2.1.2, the differences between shale gas and conventional gas occur upstream. For this study it is assumed that shale gas is of similar composition as conventional gas and can be used in power plants equal to those used for conventional natural gas. All data for this phase are therefore equal to the data in section 3.1.2.

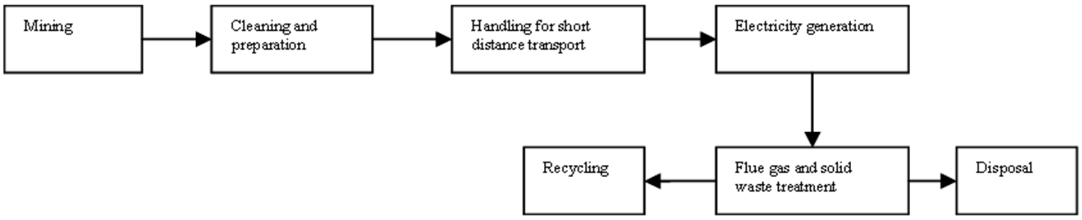


Figure 3.3: Schematic representation of the coal electricity generation system. From Hondo, 2005; Sokka et al., 2005; Ecoinvent Centre, 2007.

3.3. Coal

The coal cycle is not complex when compared to the natural gas cycle or especially the nuclear cycle. The coal combusted in the Netherlands comes from a variety of countries, as indicated in chapter 2 in Table 2.2. The coal production cycle is illustrated in Figure 3.3, transportation between the countries of origin and the Netherlands are assumed to be by ocean freighter. Distances and emissions were taken from Ecoinvent Centre, 2007. Transport from mine to port is commonly by train.

3.3.1. Mining and processing

Coal mining is carried out in two types of mines; open-pit (surface) mines and underground mines. In open-pit mines, the soil (overburden) is excavated until the coal seam is laid bare. Coal is excavated by large, slow moving diggers and transported to a central facility by either large trucks or conveyor belts.

An important consideration with coal mining is the well-known fact that layers of coal generally contain varying amounts of methane. This causes health and safety risks especially in underground mines, but of course, methane is a very potent GHG. Methane emission rates vary significantly per country (Bibler et al., 1998), mainly due to the facts that the amount of methane in coal seams varies per coal mine and in some countries more methane is drained from mines and used (Bibler et al., 1998) than in others. Aside from material inputs for the infrastructure, energy inputs include explosives, diesel for the operation of machinery and electricity.

The raw coal coming from the coal mines is processed to increase the quality and energy content per unit of weight. Impurities such as rocks are removed and the coal is crushed to reduce particle size. Inputs, other than energy, for this process include sodium bicarbonate ($NaHCO_3$) and sodium hydroxide (NaOH) (Sokka et al., 2005). In processing, diesel and electricity is used.

3.3.2. Transportation

Table 3.7 gives an overview of the modes and distances of transportation from coal mine to the Netherlands, per country. Transportation data was taken from Ecoinvent Centre, 2007. This data gives specific transport distances per country or region of origin and includes local (by train) and overseas transportation distances and emissions. Furthermore, (partial) empty return trips are included. Within the Netherlands, it is assumed that the coal is transported for 50 km by barge from the transfer port to the power plant. This distance is based on average distance of power plants from the main port where coal is unloaded from the ocean freighters (Ecoinvent Centre, 2007). Currently, all Dutch coal fired power plants are situated at a river or port, eliminating the need for road transport.

Table 3.7. Overview of transportation modes and distances. Source: Ecoinvent Centre, 2007.

Country of origin*	Distance (train; km)	Distance full load (ocean freighter; km)	Distance empty return (ocean freighter; km)
South Africa	580	13500	13500
Colombia	200	8500	8500
United States	800	7420	7420
Australia	200	23000	8000
Indonesia	200	20000	8000

3.3.3. Electricity generation

Average electricity generation was investigated. Average efficiencies were based on Seebregts & Volkers, 2005 and IEA, 2010b and typical power plant design was taken from Ecoinvent Centre, 2007. The requirements for the power plant and the associated emissions as taken from the Ecoinvent database include decommissioning.

3.3.4. Waste management

Of the fossil fuels studied, coal combustion results in the highest amount of waste, both gaseous and solid. In the flue gas, a variety of gases are present apart from CO_2, most notably SO_2. These gasses have to be scrubbed out of the gases. Energy and material requirements for scrubbing are included in power plant operations. In a report about waste production and management in the Netherlands it is reported that over recent years the solid wastes from coal fired power plants have been 100% recycled (SenterNovem Uitvoering Afvalbeheer, 2009). These wastes include fly ash, bottom ash and gypsum used for desulphurisation and are all used as raw ingredients for building materials such as concrete and asphalt. It is however questionable if all the solid wastes can be recycled in the future considering the planned increase in coal fired electricity production in the Netherlands.

3.4. Wind

Compared to natural gas and coal, wind power supplies a very small fraction of Dutch domestic electricity consumption (Table 2.1). However, since the amount of solar radiation in the Netherlands is often deemed too low for large scale power generation, wind is seen as the most viable option to produce renewable electricity on a large scale (Jacobson & Delucchi, 2010). Currently, most wind turbines are situated onshore. However, with wind being more prevalent offshore, there is more attention for large wind turbine parks off the coast in the North Sea. Two large wind farms have already been built, and more are proposed. In this study, both on- and offshore wind turbines are investigated. The main differences between on- and offshore turbines are (Jungbluth et al., 2005):

- Offshore turbines are typically of higher capacity and
- Onshore turbines have typically a longer lifetime for foundation and tower

The production chain of wind energy is not as elaborate as other chains investigated in this study. This is illustrated in Figure 3.4. The first stages of the cycle are production of the upper part of the installation, the rotor, nacelle and the electronics and mechanics followed by the construction of both the concrete foundation and the steel tower. Subsequently, the manufactured parts are assembled in and onto the tower. When the assembly is complete, the wind turbine can enter the operational phase, in which electricity is delivered to the grid. Occasional maintenance is needed, to replace or repair parts of the wind turbine, as well as to apply lubricants.

3.4.1. Production of hub, nacelle and rotor

There are many production facilities for wind turbines around the world. Currently, most of the turbines operational in the Netherlands have been manufactured in Denmark by the Danish firm Vestas. This firm currently holds the largest market share in wind turbine production worldwide. The material requirements for a new turbine that can be used both onshore and offshore are given in Table 3.8. The energy used during production is taken from Vestas, 2006b; Ecoinvent Centre, 2007; D'Souza et al., 2011.

3.4.2. Construction of foundation and tower

At the desired location, a concrete foundation is built on which a tower is constructed. The height of the tower can vary, mostly according to the capacity of the wind turbine. Higher capacity wind turbines generally require higher towers. The material requirements for constructing the foundation and the tower are given in Table 3.8.

In many studies, it is reported that the foundation for offshore wind turbines requires much more steel and concrete compared to onshore turbines. However, more recent technological developments allow offshore wind farms to be built on so called “monopile” foundations, which is a high strength steel tube that is rammed into the ground. Contrary, onshore wind turbines are still built on large concrete foundations.

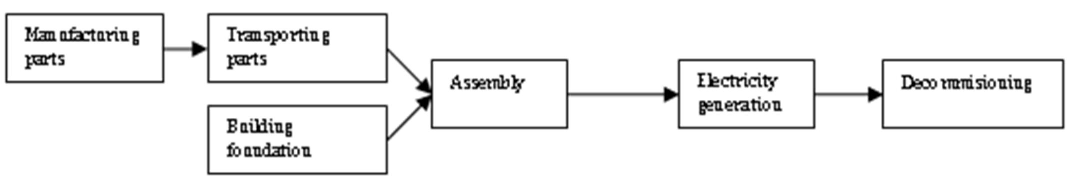


Figure 3.4: Process diagram of the wind electricity system. Source: Hondo, 2005; Vestas, 2006a

Grid connection

To supply the produced electricity to the grid, a connection must be made from the sometimes distant location of the wind turbine to the already in-place electricity grid. Based on the two existing offshore wind farms in the Netherlands, the distance to the grid is estimated at 20 km. Material requirements for the grid connection were extrapolated based on existing data on offshore wind turbines closer to the coast and grid.

3.4.3. Transportation

As the wind turbine parts from Vestas are produced in Denmark, it is assumed that the transportation of all parts to the desired site is by truck, for a distance of 1000 km for all parts, except the tower (700km) and foundation (200km) (D'Souza et al., 2011). These conditions aim to represent an average location relative to Vestas production facilities in Europe.

Table 3.8. Material and energy requirements for the production of the Vestas V112 wind turbine. Source: Vestas, 2006a; Vestas, 2006b; D'Souza et al., 2011. Foundation and tower materials include the connection to the electricity grid. Concrete is reported in cubic meters rather than kilograms.

Moving parts (both onshore and offshore)		
Materials:	**Amount (kg):**	
Aluminium	3424.2	
Cast Iron	65757.6	
Steel, high alloyed	43697	
Steel, low alloyed	201030.3	
Copper	4857.6	
Lubricating oil	1272.7	
Polyethylene, HDPE	2666.7	
Polyvinylchloride	16697	
Glass fibre reinforced plastic	24000	
Synthetic rubber	1272.7	
Polyurethane foam	363.6	
Acrylic varnish	757.6	
Bitumen sealing	7.3	
Foundation and tower		
Materials:	**Amount (kg):**	
	Onshore	**Offshore**
Concrete	*475 m^3*	-
Copper	3900	22285
Epoxy resin	547	547
Gravel	300000	1700000
Lead	7580	43300
PVC	3500	20000
Reinforcing steel	45181	203000
Steel, low alloyed	156000	156000

3.4.4. Operation and maintenance

In an LCA of wind turbines from Danish firm Vestas, it is "conservatively estimated" that their wind turbines need replacement of half of their gearbox or generator in their 20 year lifetime (Hondo, 2005; Vestas, 2006a). Furthermore, the moving parts need to be regularly lubricated, requiring a round trip of maintenance crew every 2 years (Ecoinvent Centre, 2007). Including inspection of the turbine, maintenance crews will visit onshore turbines twice a year with a passenger car and offshore turbines 4 times a year, once by boat and three times by helicopter (Vestas, 2006b). An inspection session (per helicopter) is estimated to take about 2 hours based on the distance from land to the wind farm and the surface area of the two Dutch wind farms.

3.4.5. Capacity factor and life time

An important consideration with production of electricity from wind is the capacity factor: the ratio of realized production to the maximum production at installed capacity. In the Netherlands, the average capacity factor in 2009 was about 24% for onshore and offshore combined (Centraal Bureau voor de Statistiek, 2011). This means that wind turbines produced 24% of the electricity they would have produced, were they operational at peak load for 100% of the time. There are big differences however between onshore and offshore capacity factors. In the same period, the capacity factor for onshore wind electricity was 22%, for offshore it was much higher, at almost 37% (Centraal Bureau voor de Statistiek, 2011). Increasing installation of offshore capacity could lead to a marked increase in the overall capacity factor. The most recently installed wind farm, the "Prinses Amalia" wind farm off the coast of northern Holland, reached a capacity factor of 41%[o] (Eneco B.V., 2011a), another recently installed offshore wind farm reaches 33% (NoordzeeWind, 2010).

[o]The capacity factor was calculated based on the installed capacity and annual electricity generation.

Although offshore wind turbines have higher capacity factors, there lifetime is usually lower (about half) when examining the foundation and tower compared to onshore wind turbines. The lifetime of the moving parts is about 20 years for both onshore and offshore, while the lifetime for foundation and tower is 40 years onshore, and only 20 offshore (Jungbluth et al., 2005).

3.4.6. Decommissioning

When a wind turbine reaches the end of its life, it is generally dismantled and partly recycled. In general, research shows that the metal components show a high recyclability of 90% and above, but that plastics and other non-metals are usually incinerated and/or land filled (Jungbluth et al., 2005; Vestas, 2006a; Vestas, 2006b; D'Souza et al., 2011). Over the years, Vestas has developed a more detailed end of life scenario with the aid of Danish companies involved in dismantling wind turbines (Vestas, 2006a; Vestas, 2006b; D'Souza et al., 2011). This scenario confirms the assumptions made in other studies but offers recycling data for almost all materials or material groups used in a wind turbine. In this study, we use the end of life scenario by D'Souza et al., 2011. Aside from recycling and land filling, the dismantling of a wind turbine also requires the operation of building machinery. The previously mentioned studies generally report that these requirements are similar to those during construction.

3.5. Nuclear

Currently, apart from test reactors, the only operational NPP in The Netherland is the Borssele power plant in the Dutch province of Zeeland. The plant is a reasonably small pressurized water reactor (PWR) currently with a capacity of 485 MW electrical output. The facility is operational since 1973 and is currently operated by EPZ (Elektriciteits-Productiemaatschappij Zuid-Nederland). A simplified illustration of the full nuclear cycle of Dutch nuclear electricity is given in Figure 2.2. In the following sections, each step in this figure will be explained in more detail.

3.5.1. Production of fuel

3.5.1.1. Mining of uranium

According to EPZ, the fuel used historically comes from different sources (tails, military uranium) but in recent years (2008-2010) the uranium used in Borssele comes from the Ulba Metallurgical Plant in Ust-Kamenogorsk in Eastern Kazakhstan (EPZ, 2010b). The uranium used in this facility is originally mined in Southern Kazakhstan, roughly between the cities of Kyzyl-Orda and Taras. All mines in this region employ in situ leaching (ISL) to extract the uranium from the ground Kazatomprom, 2008). In ISL mining, a source rock with a concentration of uranium of about 0.03-0.05% is dissolved with an acid solution (Storm van Leeuwen, 2008; World Nuclear Association, 2010a).

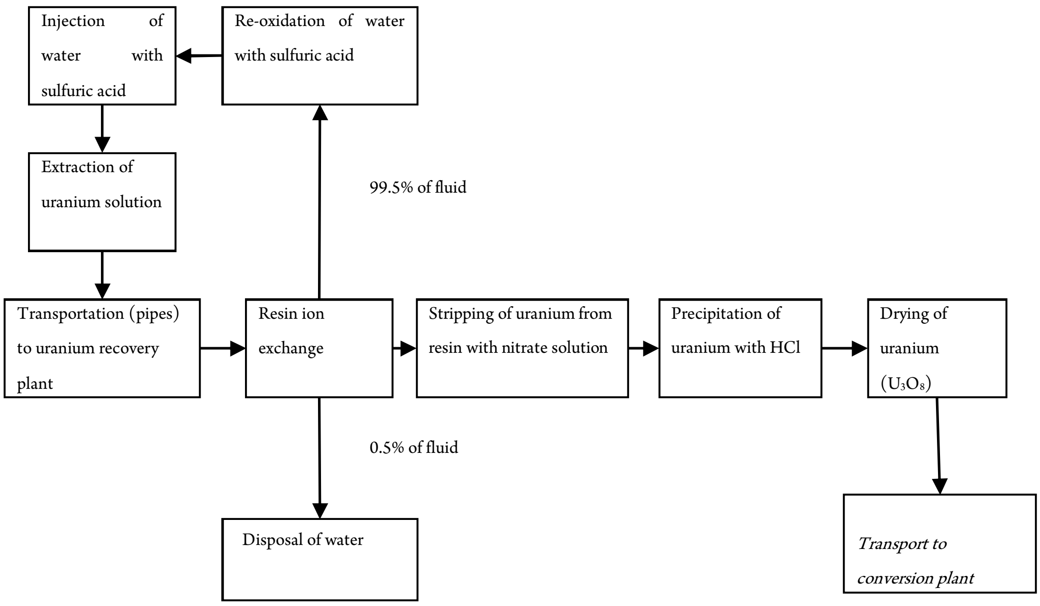


Figure 3.5: Schematic representation of the uranium mining cycle via ISL mining.

The mining process includes the following steps: First, the uranium plant and injection, extraction and monitoring wells are constructed and connected to the plant. After construction is finished, a solution is injected through the injection wells, containing an acid to extract the uranium. In Kazakhstan, compared to other countries, relatively much sulphuric acid is used; with ranges being reported of 18-150 kg acid per kg of uranium (Mudd, 2001), although smaller ranges (70-80kg acid/kgU) are being reported by the World Nuclear Association for Kazakhstan specifically (World Nuclear Association, 2010b). The acid solution (called liqor) then flows through the uranium ore, dissolves the ore and uranium. The solution with uranium is extracted at the extraction wells some time later; higher doses of acid are employed to reduce the time between injection and extraction (Kazatomprom, 2008).

In uranium recovery facilities in Kazakhstan, the uranium is extracted from the solution via resin ion exchange. The uranium binds to the resin because of its (negative) charge. After this, the uranium is stripped from the resin with a nitrate solution. The uranium is precipitated from this solution with hydrogen peroxide, after which the uranium is dried, resulting in 80-100% U_3O_8. This uranium oxide concentrate is called yellowcake. The process of resin ion extraction is also performed with ‘regular’ uranium mining where, after the ore is mined and milled, a sulphuric acid solution is used to extract the uranium, although the amount of sulphuric acid used in ‘regular’ mining is much lower than found for ISL.

The remaining extraction fluid from which the uranium is extracted is reinjected into the injection well. About 0.5% of this fluid is however disposed of in other wells that are no longer productive (World Nuclear Association, 2010b). The full cycle of uranium mining is illustrated in Figure 3.5 and the different processes are summarized in Table 3.9.

In literature there are not many studies available detailing material and energy requirements of ISL mining, as more common methods (surface and subsurface mining) are more common. The study by Storm van Leeuwen assessed the energy requirements of ISL mining based on the inputs of sulphuric acid and ammonia. This shows that when assuming 100 kg of sulphuric acid and 3 kg of ammonia is used per kg of Uranium produced, about 0.547GJ/kgU of primary energy is needed (Storm van Leeuwen, 2008). However, this data does not include construction and operation of the well field and is not specific for Kazakhstan.

Table 3.9: Processes involved in ISL uranium mining.

Process	Remarks/explanation	Step #
(Construction of uranium plant)	-	1
(Drilling of wells)	-	2
(Connection of wells to plant)	-	3
Pumping of water with acids in	A solution of complexing reagents (acids or alkali, depending on the condition of the source rock). The amount of acid needed is about 70-80kg sulphuric acid/kgU.	4
Extraction of water with dissolved uranium	Solution is pumped out of the ground and to the uranium plant.	5
Resin Ion Exchange	The uranium is separated from the solution by binding it to oppositely charged ions fixed in resin.	6
Waste treatment	About 0.5% of the water from which the uranium was extracted in step 6 is pumped into disposal wells. The remaining 99.5% is refortified with chemicals to be reused from step 4 onwards.	6w
Stripping uranium from resin	After this, the uranium is stripped from the resin with a nitrate solution	7
Precipitating and drying uranium	The uranium is precipitated with hydrogen peroxide and dried to 80-100% dry U_3O_8 (yellowcake). This yellow cake is further converted to fuel pellets/rods in the conversion cycle.	8
Restoration of mine	After the mine is depleted, it should be restored to similar conditions as before the mine was built and used	9

As ISL is also not included in the EcoInvent database, an own module was added to include ISL well fields and other requirements including their construction, based on a preliminary assessment by Powertech Uranium Corp. This study details the finances of a proposed ISL project in the United States SRK Consulting Inc., 2010. From this report, the number of wells and other facilities were taken and assumed to be typical for an ISL field. The lifetime and total uranium production from this “typical” ISL facility was based on estimates in the same report. The total requirements for the ISL facilities are given in Table 3.10. Inputs that are specific to the location (such as electricity) are all assumed to have been produced in Kazakhstan. It was assumed that the injection and extraction wells are drilled in a process similar to that of oil and gas well drilling, with the exception that no drilling mud, but only water is used as a drilling fluid. The requirements and associated emissions were modelled based on the Ecoinvent database (Ecoinvent Centre, 2007). In gas and oil well drilling, drilling mud is used to counter the pressure from the underlying oil or gas field. All inputs involved with drilling mud are removed in the ISL module. An average well depth of 200 meters was assumed, a value which is in between the maximum depth of uranium deposits suitable for ISL in Kazakhstan and the average depth of such deposits in Australia (World Nuclear Association, 2011).

Table 3.10: Requirements for the construction of an ISL well field. Data is based on a project proposal for an ISL well field in the United States that should produce 3813 metric tons of uranium (SRK Consulting Inc., 2010). Well requirements and high density polyethylene (HDPE) production requirements were taken from the Ecoinvent database (Ecoinvent Centre, 2007).

Requirement	Amount	Unit	Remarks
Injection wells	3510	-	From SRK Consulting Inc., 2010
Extraction wells	1800	-	From SRK Consulting Inc., 2010
Wells total	1062000	Metre	Average depth of 200 meters per well (World Nuclear Association, 2011)
HDPE pipelines	265500	Metre	Average well spacing of 50 meters was assumed based on (World Nuclear Association, 2011)
HDPE	1881948	kg	Weight was calculated based on density of HDPE

3.5.1.2. Conversion of uranium oxide to uranium hexafluoride (UF_6)

The yellowcake produced in the mining step discussed in the previous section is still very low in U-235, the radioactive compound needed in nuclear reactors. In order to enrich the substance to about 3-5% U-235, the yellowcake first has to be converted into UF_6, a compound of uranium and fluoride, which is solid at room temperature but can easily be converted into gas. U-235 can only be separated from the mixture in this gaseous phase.

The yellowcake produced in southern Kazakhstan is transported to Angarsk in southern Siberia, Russia to a conversion facility operated by Tenex. Here, the yellowcake produced in the last step of the uranium mining cycle is converted to uranium hexafluoride (UF_6), in eight separate steps:

- First, the uranium in the yellowcake is dissolved with a warm solution of nitric acid.
- Then, the uranium is separated from this solution with tributylfosphate.
- It is again extracted from this with nitric acid.
- The uranium is precipitated as uranylnitrate.
- This is converted to UO_3
- UO3 is reduced to UO_2.
- With Hydrogen Fluoride, UO_2 is converted to UF_4.
- This is converted to UF_6 by exposing UF_4 to F_2 gas.

After this conversion, the gaseous UF_6 is cooled down and solidifies. The depleted UF_6 is also solidified, and is also radioactive, thus it is treated as nuclear waste and has to be stored accordingly. The solidified UF_6 is packaged in special containers for transportation to the enrichment facility. The enrichment steps are illustrated and summarized in Figure 3.6 and Table 3.11 respectively.

As with uranium mining, reports on energy consumption and GHG emissions from uranium conversion vary widely. Different studies place the energy requirement for conversion of uranium from $7MW_{th}/tU$ to $14.6MW_e$ and $396MW_{th}$ (Lenzen, 2008).

3.5.1.3. Enrichment of UF_6

After the yellowcake is converted to UF_6, it is enriched in Angarsk in a nearby enrichment facility. No transport is assumed between the conversion and enrichment facilities, as they appear to be located near each other. In the enrichment facility, first, the UF_6 is heated to evaporate it, after which the pressure of this gas is reduced. Then it is fed into an enrichment cascade of centrifuges. Because of the centrifugal force, the heavier U-238 in the mixture builds up against the outer layer of the centrifuge, and the U-235 builds up more towards the centre of the centrifuge. After separation, the process is repeated many times. When the UF_6 has passed through the entire cascade, it is again solidified for transport to the fuel production facility.

Table 3.11: Detailed description of uranium conversion, enrichment and fuel production.	
Process	**Remarks/explanation**
(Construction of conversion plants)	
(Construction of enrichment plants)	
(Construction of fuel fabrication plants)	
Conversion of yellowcake to UF_6:	Dissolve uranium from yellowcake with nitric acid Separation into tributylfosphate Extraction with nitric acid Precipitation of uranium as uranylnitrate Conversion to UO_3 Reduction to UO_2 Conversion to $UF_4$with HF Conversion to UF_6 with F_2 gas Cooling and packaging
Enrichment	Heating of solidified UF_6 Pressure reduction Gaseous centrifuge enrichment cascade Cooling down of enriched and depleted UF_6. Packaging
Fuel production	Conversion to UO_2 Pelletizing Sintering at 1400 °C Insertion in fuel rod Production of fuel rod assembly Packaging for transport
Transportation to power plants	From Ust-Kamenogorsk to Borssele

Centrifuges used for enrichment of uranium are commonly powered by electricity. The same is assumed for the facility in Angarsk. Electricity requirement is reported to be 80 kWh_{el}/kg SWU[p] in Russia (Dones et al., 2007). This value only represents operation of the enrichment facility and does not include construction. Furthermore, apart from electricity, some heat is required in the enrichment process. The heat requirement and energy requirement for construction are summarized in Lenzen, 2008. Total energy requirements including construction and heat for operation amount to 167 kWh_e/kg SWU.

3.5.1.4. Fuel production

After enrichment in Angarsk, the enriched UF_6 is transported to the Ulba Metallurgical Plant in Ust-Kamenogorsk, some 550 km from Angarsk. Here the fuel pellets and assemblies are produced that are used in Borssele. The UF_6 is first converted to UO_2 and compacted into pellets. Almost all nuclear reactors utilize UO_2 as a fuel. These pellets are sintered in an oven at 1400°C to increase the cohesion of the UO_2 particles. The pellets are put into a steal tube which is welded shut. This tube is a fuel rod and it is incorporated into a fuel rod assembly, together with several other fuel rods, as used in the power plant. After producing this assembly, the fuel is ready for use. It is transported from Kazakhstan to Borssele.

---

[p]SWU = Separative Work Unit. A separative work unit is a unit that defines the amount of work that a centrifuge cascade needs to perform in order to enrich uranium. The amount of SWU needed is defined by the mass of feed uranium, and the percentage of uranium-235 in the feed, product (enrichment grade) and the tails (tails assay) (Lenzen, 2008). See also Appendix A.2.

3.5.2. Electricity production

3.5.2.1. Construction of the power plant

In order to be able to assess the specific Dutch situation, two specific NPP designs were studied. Firstly, the design of the currently operational Borssele power plant, and secondly, the design of a proposed second NPP for The Netherlands. Two organizations are currently planning to build a new NPP: Energy Resources Holding B.V. and Delta Energy B.V. Both plan to build a PWR plant of the third generation with a capacity of ≤ 2500 MW_e (Delta Energy B.V., 2009; Energy Resources Holding B.V., 2010). Both organizations plan to use a mixture of natural uranium and recycled/MOX[q] fuel in order to cope with price fluctuations of uranium.

In literature, there are three distinct approaches in calculating the energy costs or GHG emissions related to construction of (nuclear) power plants. The first is based on process analysis, much like the greater part of this study, but the second and third are based on economic input-output analysis, where the monetary value of power plant construction is used to calculate the emissions, based on the average emissions per unit of currency in the economy. Methods applied in economic input-output analysis are either based on

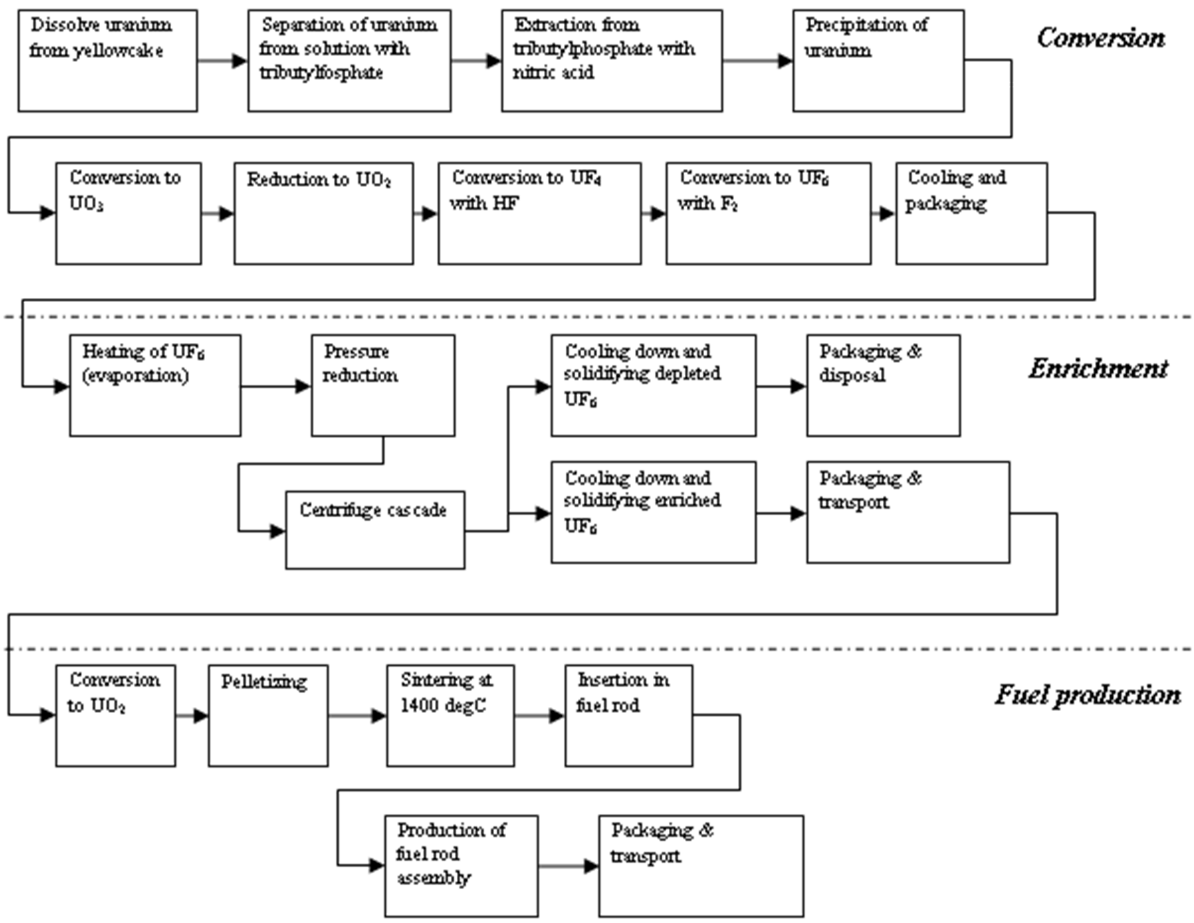


Figure 3.6: Detailed process diagram of the conversion, enrichment, and fuel production stages. Source: World Nuclear Association, 2010b

[q] MOX fuel or Mixed Oxides fuel is a nuclear fuel that uses a mix of uranium and plutonium oxides (UO_2 and PuO_2), contrary to "normal" fuel elements that only contain uranium oxides (UO_2). MOX fuel is a way to reuse low grade uranium and waste plutonium, either from nuclear weapons or from reprocessing facilities that treat spent fuel.

Average Economic Intensity (AEI), where the monetary value of the power plant is multiplied with the average GHG intensity of the whole economy, or are a hybrid between process analysis and EIO. In the latter case, the investment for the power plant is divided and costs are allocated to different sectors (e.g. metal to the metal industry, machinery to the machinery industry, services to the services sector). This variety in approaches leads to great differences in the resulting emissions associated with construction of NPPs, ranging from 1177 to 17198 GW_{th}/GW_e (Lenzen, 2008). The GHG emissions estimate in this study is primarily based on direct material and energy inputs (process analysis); minor inputs (like labour activity) are based on EIO analysis allocated to specific sectors.

There are many types of nuclear reactors, but within each type there are no great differences between designs. Table 3.12 gives an overview of a standard, 1000MW, Pressurized Water Reactor (PWR). Literature data on PWR's of comparable size to that in Borssele is not readily available. Therefore, investment cost and material requirements are scaled down from a 1000MW reactor to the 485 MW reactor size. It is common for electricity generation units to have economies of scale. This means that when the capacity of a power plant increases, the relative (per unit of capacity) requirements to build the plant decrease. However, research has shown that at least when considering investment costs, nuclear reactors have no significant economies of scale (Cantor & Hewlett, 1988; Marshall & Navarro, 1991). The conversion to Borssele's size is included in Table 3.12, as are the emissions associated with the input of materials and energy. Table 3.12 also features the material requirements for the proposed new reactor(s) (as mentioned before in this section) to analyse marginal GHG emissions. The reactors that are proposed to be used are so-called generation III+ reactors, the next generation compared to Borssele's PWR, with allegedly higher efficiency and most notably, passive safety systems. Proposed manufacturers of these plants stress the fact that safety and economics have increased (Areva, 2011; Westinghouse, 2011) and even material requirements could be much lower (Westinghouse, 2011). However, concurrently, there is mention of the use of extra materials for the increased safety systems. Therefore, the assumption is made that the requirements per MW_e of capacity have remained similar.

Table 3.12: Material and energy requirements for the construction of a typical current generation 1000MW PWR, the Borssele reactor (estimated) and a proposed reactor for the Netherlands. Data from Dones et al., 2007. Italic text indicates that a unit other than metric tons is used.

Component / input	**1000 MW PWR**	**512 MW Borssele PWR**	**2500 MW Proposed PWR plant**
	Amounts needed (metric tons)	**Amounts needed (metric tons)**	**Amounts needed (metric tons)**
Steel reinforcing bars	33680	17244	84200
Structural steel (low alloyed)	5570	2852	13925
Total components (high alloyed)	21911	11218	54778
Copper	1473	754	3683
Aluminium	200	102	500
Concrete	*169200 m^3*	*86630 m^3*	*423000 m^3*
Fibre cement	5300	2714	13250
Oil	200	102	500
Wood	*6720 m^3*	*3441 m^3*	*16800 m^3*
Paper	850	435	2125
Light oil in heating	*27 TJ_{th}*	*14 TJ_{th}*	*68 TJ_{th}*

3.5.2.2. Operation and maintenance of the power plant

During the operation of the plant, the uranium in the fuel is fissioned into its decay products, releasing large amounts of heat. This heat is used to power steam turbines. During operation, energy is used for cooling and managing purposes (Sovacool, 2008); maintenance and refurbishments when the reactor is shut down consume both energy and materials (Lenzen, 2008). As with the construction of the plant, a variety of approaches is used in literature to determine the energy requirement and GHG emissions of operation and maintenance of a NPP. As with the construction of the NPP, the operation and maintenance requirements are assessed in literature with a variety of methods. The analysis in Storm van Leeuwen, 2008 again uses the AEI method and found the energy requirements for O&M, including refurbishments of NPP components, to be 791 $GWh_{th}/GW_e.y$ (gigawatthour per gigawatt of NPP capacity per year) and 165 $GWh_e/GW_e.y$ (for full load years). Based on hybrid EIO analysis, the energy requirements are found to be substantially lower, at 318GWh$_{th}$/GW$_e$.y and 12GWh$_e$/GW$_e$y, again for full load years (Lenzen, 2008). As mentioned before, EIO divides the cost of, in this case operation and maintenance, over different sectors instead of using average energy intensity for the whole economy as AEI does. As it is often argued that AEI produces an overstatement of the emissions, in this study, the value found in Lenzen, 2008 is used, also because this value is close to the average of several other studies reviewed in Lenzen, 2008. Other requirements, such as those for the treatment of flue gas and waste water are included in the Ecoinvent database.

3.5.2.3. Decommissioning of the power plant

The Borssele power plant was set to halt operation in 2013; however, this has been extended to 2033 (Ministerie van Economische Zaken, Landbouw en Innovatie, 2011). After operation, the Borssele power plant is said to be decommissioned right away. A lot of the waste from the power plant will have to be stored as radioactive material (Storm van Leeuwen, 2008). A variety of approaches to decommissioning is currently proposed, namely entombment (power plant is sealed in a concrete tomb), immediate dismantling, and dismantling after a waiting period of 50-100 years (Dones, 2005; Sovacool, 2008; Storm van Leeuwen, 2008). There is however not much experience with decommissioning of NPPs, as most power plants are still operational, or have not been decommissioned yet. The Dodewaard NPP, a small facility which operated between 1969 and 1997 in the Netherlands, is scheduled to be disassembled in 2045, after a period of containment (1997-2005) and a waiting period of 40 years[r]. Due to the lack of experience, not much is known concerning the costs (both monetary and in energy terms) of decommissioning a NPP.

After operation has been shut down, the spent fuel is removed and the plant is hermetically closed to contain all radiation. When demolition starts, first the radioactive materials are removed to prevent contamination of other materials. The radioactive materials have to be processed and stored just like radioactive tails. Table 3.13 lists the amount of waste material produced by decommissioning the same power plant that was the basis for the data in Table 3.12.

Table 3.13: Overview of the amounts and types of radioactive wastes produced by the decommissioning of a nuclear power plant. Source: Lenzen, 2008

Type of waste	Amount (tonnes)
Low to medium radioactive waste	10,000
Highly radioactive waste	10,000
Non-radioactive waste	100,000

The energy requirements for decommissioning as estimated in several studies vary from about 3% to over 200% of construction requirements (Lenzen, 2008). Partly, this variation is caused by the different methods used in the assessment of decommissioning requirements (cf. section 3.5.2.1). Excluding the approach used by Storm van Leeuwen (average economic intensity) reduces the variation in the results. However, a range of uncertainty still remains. As there is as of yet very little experience in decommissioning costs of NPPs, a range of decommissioning requirements is tested in section 5.5 to assess the influence of decommissioning costs on the overall result. In this study, a value of 10% of construction energy requirements is used based on the average value found in Lenzen, 2008. Furthermore, the requirements for the radioactive waste produced during decommissioning are calculated based on the Ecoinvent database figures for nuclear waste treatment and the amounts of waste given in Table 3.13.

3.5.3. Waste treatment

Borssele produces waste in three forms: gaseous, liquid and solid. Used fission rods are generally referred to as a separate category of waste. Gaseous and liquid waste is filtered/treated on site and its' contribution to the life cycle GHG emissions have been covered in the previous section. Small amounts of radioactivity are released to the atmosphere and the Westerschelde. Solid waste is produced in two types: low-to-medium radioactive waste (LMRW) and highly radioactive waste (HRW). LMRW is transported directly to COVRA[s], the Dutch facility for the collection, processing and (temporary) storage of various types of radioactive waste. COVRA is situated next to the NPP. HRW (used fuel) is stored in water in an internal cooling basin at Borssele until the heat production of this

[r]Source: http://www.kcd.nl/index1.html, information website for the former nuclear power plant 'Dodewaard'

[s]COVRA stands for "Centrale Organisatie voor Radioactief Afval" (Dutch) or central organization for radioactive waste.

waste is lowered enough to transport it. The fuel assemblies are put into transport containers and transported to AREVANC in La Hague, Northern France, for the biggest distance by train.

At AREVANC, in a chemical process, the fuel is separated into uranium (95%), plutonium (1%) and waste (Scheepers et al., 2007). The waste is packaged as highly radioactive waste. The waste is sealed in glass (vitrified) and put in steel barrels, this type of waste is so radioactive that it produces about 1kW of heat per 180 litre barrel for the first years and therefore has to be cooled. The second type of waste is technological debris such as filters of the gas and water treatment, but also the metal cylinders of the fuel assemblies (EPZ, 2010a). This is compacted into the same 180 litre barrels but does not require cooling. The waste will be transported back to COVRA in NL by train. Yearly, about 8.5 barrels of highly radioactive and about 8 barrels of less radioactive waste (amounting to less than 3 m^3 total) are produced at AREVA NC from Dutch waste. These are transported to COVRA in transports of 20 to 48 barrels (EPZ, 2010a).

The plutonium is stored at La Hague until it is needed for MOX production, the uranium is converted to UF_6 (for re-enrichment) or U_3O_8 (down blending of highly enriched military uranium) at another factory in Pierrelatte in Southern France (EPZ, 2010a).

3.5.4. Uranium losses

During the nuclear cycle, varying fractions of the uranium processed are lost in waste streams. According to (Storm van Leeuwen, 2008), 5% of input uranium is lost at conversion, again 5% of the input at enrichment, and another 10% of input uranium is lost during fuel fabrication. These losses are included as they increase the overall demand for uranium per kWh of electricity produced.

Table 3.14: Waste management processes of the nuclear powered electricity cycle

Process	Step #	Remarks/explanation
Treatment of gaseous and liquid	1	On-site at power plant. Energy penalty?
Packaging of solid	2	Packaged in unknown containers. Wastes packed are fission rods but also lower radioactive materials (technological waste) such as the filters used in step 1.
Transport to COVRA	2-3t	Transport (by road, truck presumably) from Borssele to COVRA (in Vlissingen-Oost). COVRA is situated next to the nuclear power plant
Interim storage	3	Storage of all waste at COVRA for a cool down period to let the radioactivity of the material decrease.
Packaging of solid	4	Solid waste is packaged in certified containers built to IAEA specs.
Transport to AREVA NC, La Hague	4-5t	Waste is transported by truck (first part 2km) and train (biggest part) to La Hague in Normandy, France (approx 660 km)
Separation of U and P from waste	5	In La Hague in France, Plutonium, that is produced as uranium decays, is separated from the fuel rods to be used in MOX fuel elements
Treatment of waste	6	
Packaging of waste:		
Glassification of high radioactive waste	7a	Waste is put in steel barrels and sealed in glass (vitrified).
Compacting of low radioactive waste	7b	Low radioactive waste is compacted to allow for more efficient transport and storage
Transport to COVRA	7-8t	The waste from Borssele is transported back to COVRA
Interim storage with cooling	8	At COVRA, the waste is stored temporarily until a decision is made for permanent storage. The waste first produces about 1kW of heat per barrel and is thus, passively, cooled
Interim storage without cooling	9	After about a year cooling of the waste is no longer required
Permanent storage	*10*	It was decided in 1984 that the waste would be stored for at least 100 years above ground before it will be stored permanently. Permanent storage locations are being researched and evaluated.

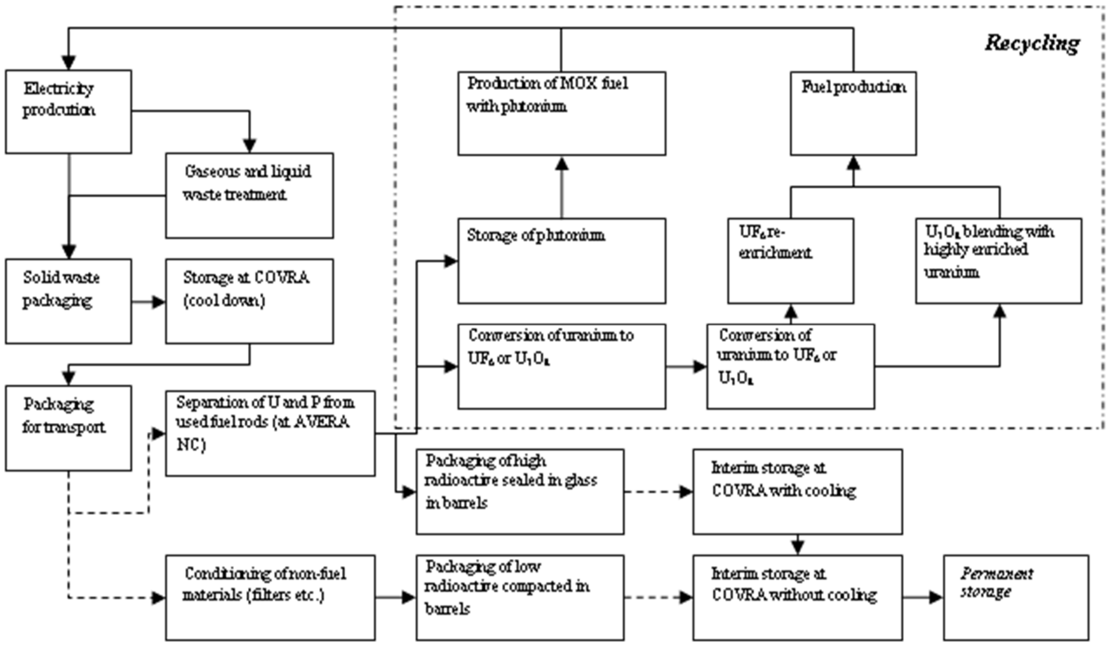


Figure 3.7.Detailed process diagram of the nuclear fuel waste management cycle. Dashed arrows indicate transportation by truck and train between La Hague, France and Vlissingen, The Netherlands. Solid arrows indicate internal movement on-site each facility.

4. Greenhouse gas emissions of electricity generation options

4.1. Overall Comparison

In Figure 4.1 and Table 4.1, the total greenhouse gas emissions are shown and compared for all of the six studied electricity generation systems. The emissions are divided into three categories as mentioned before (cf. first page of chapter 2): upstream emissions, direct emissions, and downstream emissions. As can be seen from this figure and as was expected, there is an obvious distinction between high emission levels (coal; 985 g CO_2-eq/kWh), medium levels (conventional and shale gas; 465 and 486 g CO_2-eq/kWh, respectively) and low emissions levels (nuclear and wind) per kWh of electricity. Shale gas has slightly higher emissions than conventional natural gas, because of an increase in upstream emissions. The lowest emissions are released in the offshore wind electricity system, at 11.2 grams of CO_2 equivalent emissions per kWh of electricity, followed by onshore wind electricity at 11.9 g CO_2-eq/kWh, contrary to many other studies. Nuclear electricity produces 39.3 g CO_2-eq/kWh.

Table 4.1: Greenhouse gas emissions figures for six different electricity generation systems in grams of CO_2-equivalent emissions per kWh of electricity.

Stage	Natural gas	Shale Gas	Coal	Nuclear	Wind onshore	Wind offshore
Upstream	22.3	42.8	104	24.4	11.7	10.8
Direct	442	442	881	13.7	0.09	0.21
Downstream	0.00	0.00	0.02	1.1	0.20	0.18
Total	**465**	**486**	**985**	**39.3**	**11.9**	**11.2**

From the graph on the left it is easily observed that direct emissions from the combustion of fossil fuels contribute the most to the total emissions per kWh of electricity, with contributions of almost 90% for coal, 91% for shale gas and 95% for conventional natural gas.

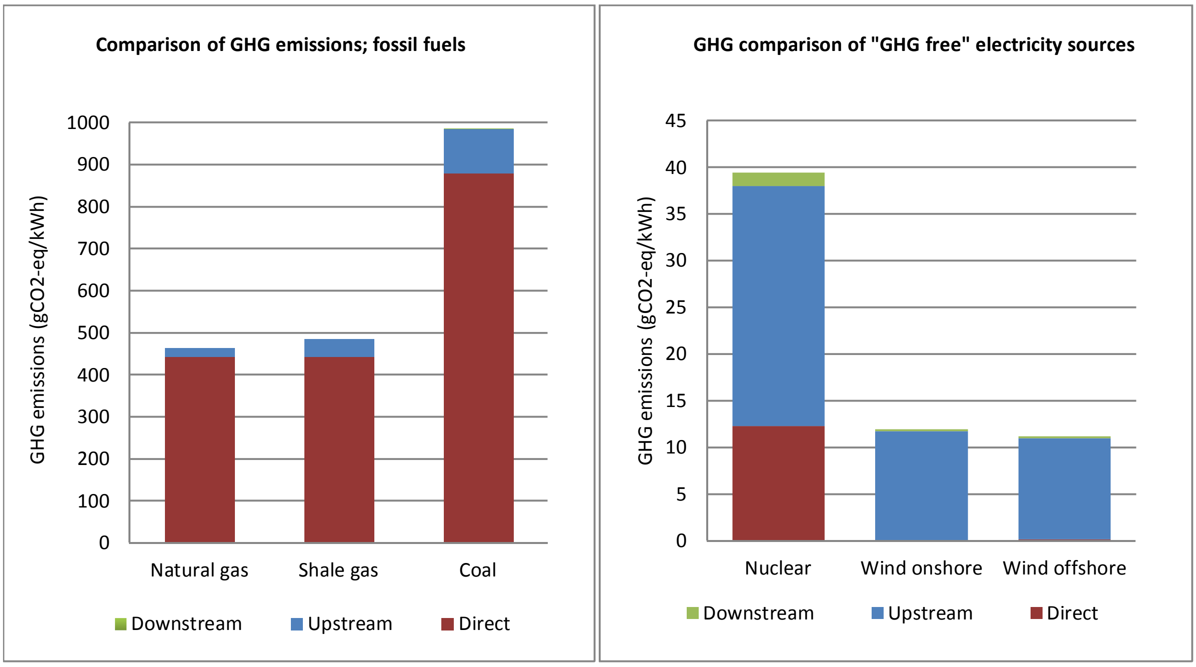


Figure 4.1: Comparison of the direct, upstream and downstream GHG emissions for six different electricity generation systems. Left: comparison of conventional natural gas, shale gas and coal electricity. Right: Comparison of nuclear, onshore wind and offshore wind electricity, systems commonly denominated as “emission free”.

Contrary to popular belief, on the right it is shown that a large fraction (35%) of emissions associated with nuclear electricity are caused by direct emissions from the operation of the power plant, but the majority of emissions are released in upstream processes (62%). For wind electricity, both onshore and offshore, almost all emissions are released in upstream processes.

The following paragraphs will examine each generation system in detail and will show the results of a sensitivity analysis of various parameters to assess each parameters importance for the overall results.

4.2. Conventional natural gas

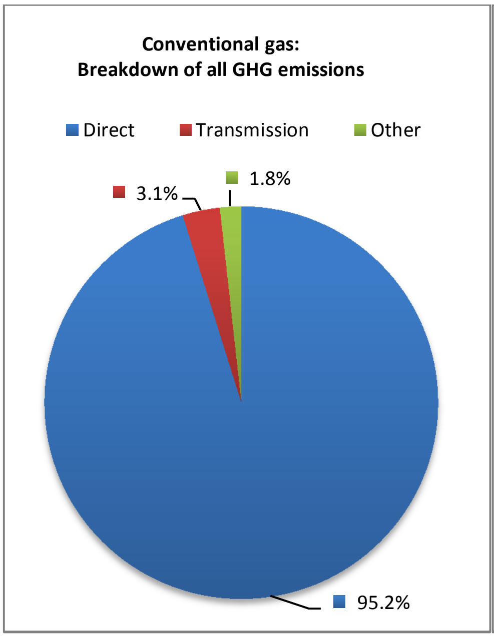
In Table 4.2 Figure 4.2 below, a breakdown is shown of the GHG emissions of the conventional natural gas system. As mentioned before, the vast majority (95.2%) of emissions is released during combustion of the gas in the power plant. When looking at upstream processes only, most emissions are released during transportation of the gas, mainly through the combustion of natural gas in compressors and the input of electricity. Overall, only about 0.15% of emissions are released during drilling and completion of the gas well. Power plant construction only adds 0.06% to total emissions per kWh of electricity including decommissioning. Operation and maintenance and waste management are almost negligible in the overall result in terms of GHG emissions.

Table 4.2: Breakdown of the GHG emissions of the conventional natural gas system per kWh of electricity generated.

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Direct	442.26	95.2%
Transmission	14.22	3.06%
Production	7.16	1.54%
Well	0.68	0.15%
Power plant	0.28	0.06%
Operation and maintenance	0.01	0.00%
Waste	0.0002	0.00%
Total	**464.61**	**100.00%**

When examining these emission breakdowns, it is clear that power plant efficiency is a very important factor in overall emissions, as the direct emissions of combusting natural gas amount to about 95.2% of total emissions per kWh electricity. The next chapter (see section 5.1) will assess to what extent a change in power plant efficiency will influence the overall result.

Direct emissions come solely from the combustion of natural gas. At a power plant efficiency of about 46% (LHV basis), an amount of 7.85 MJ of natural gas is needed per kWh of electricity generated. The combustion of this amount of natural gas releases about 442 grams of CO_2. Other GHGs released in this process are methane, nitrogen oxides and other organic combustion gases, but only in very small amounts. Transmission emissions are caused mainly by the combustion of natural gas in gas motors and heating of the natural gas transported.



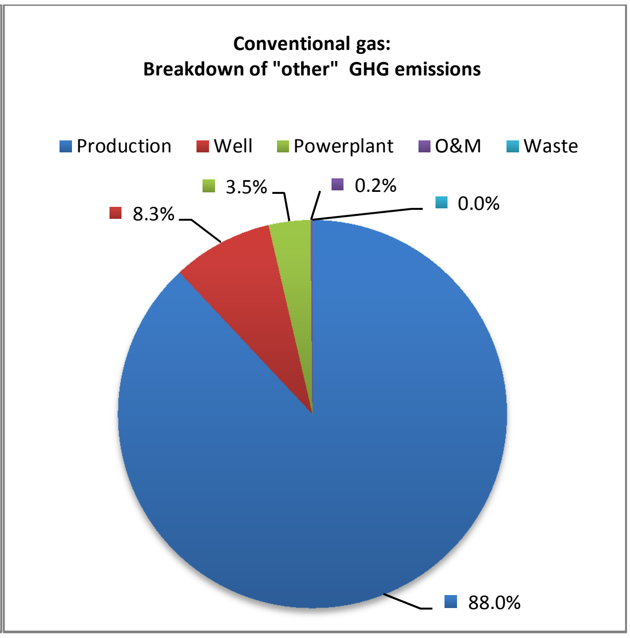


Figure 4.2: Breakdown of the GHG emissions of the natural gas electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category “other” as shown left.

10% LNG scenario

Below the results are presented for the scenario where 10% of the Dutch natural gas supply is LNG (Table 4.3 and Figure 4.3). The basis for these results is equal to that of the previous section covering the results for conventional natural gas; however, ten per cent of the supply of Dutch gas is substituted with LNG from Algeria.

Table 4.3: Breakdown of the GHG emissions of the 90% conventional natural gas + 10% LNG system, per kWh of electricity generated.

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Direct	442.26	91.9%
Import LNG	15.96	3.32%
Transmission	13.36	2.78%
Production	6.44	1.34%
Well	0.62	0.13%
Power plant	0.28	0.06%
O&M	0.01	0.00%
Waste	0.0002	0.00%
Total	**478.93**	**100.00%**

As can be seen below, increasing the share of LNG in the total gas supply leads to an increase in total GHG emissions. The imported LNG, at only 10% of supply, accounts for 3.3% of total emissions, or 43.6% of all upstream emissions, while total upstream emissions for the remaining 90% of natural gas supply account for about 4.3% of total emissions. Compared to the 100% conventional natural gas system, upstream emission for the production of Dutch gas are somewhat lower per kWh, because of the decreased amount of this Dutch gas used per kWh. When examining the emissions associated with LNG import, the main sources of emissions are liquefaction and transport via LNG tanker. A breakdown of the emissions associated with LNG production, transport and delivery to the Dutch gas grid is given in Figure 4.4. Especially liquefaction, which requires the gas to be cooled to -162°C, requires large amount of energy. The emissions released as a consequence of this energy use are for example roughly three times as high as the emissions released during production of the gas that is liquefied at 48% of all LNG related emissions.

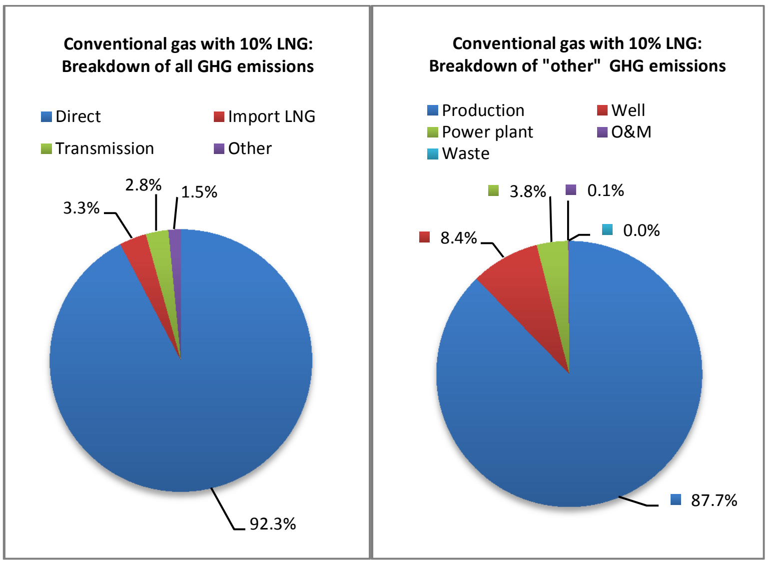


Figure 4.3: Breakdown of the GHG emissions of the 90% conventional natural gas + 10% LNG electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category "other" as shown left.

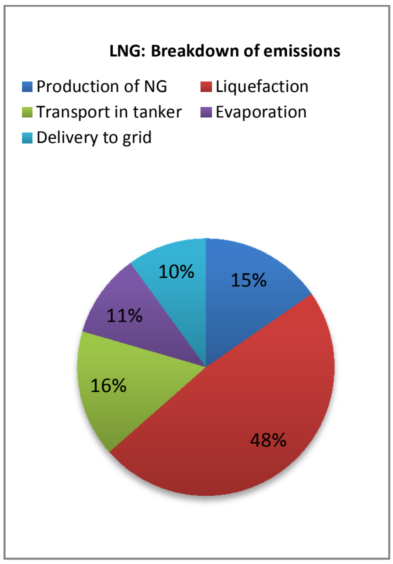


Figure 4.4: Breakdown of the GHG emissions of LNG production, transport, and delivery to the Dutch gas grid.

10% Russian gas scenario

Below the results are presented for the scenario where 10% of the Dutch natural gas supply is Russian gas (Table 4.4 and Figure 4.5). The basis for these results is equal to that of the previous section covering the results for conventional natural gas; however, ten per cent of the supply of Dutch gas is substituted with conventional natural gas from Russia. The overall results are very similar to those obtained in the 10% LNG scenario, although the emission sources are very different.

Table 4.4: Breakdown of the GHG emissions of the 90% conventional natural gas + 10% Russian natural gas system, per kWh of electricity generated.

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Direct	442.26	91.9%
Import Russian CNG	18.05	3.75%
Transmission	13.36	2.78%
Production	6.44	1.34%
Well	0.62	0.13%
Power plant	0.28	0.06%
O&M	0.01	0.00%
Waste	0.0002	0.00%
Total	**481.03**	**100.00%**

As can be seen below, including a 10% share of Russian gas in the total gas supply leads to an increase in total GHG emissions. The imported Russian natural gas, at only 10% of supply, accounts for 3.8% of total emissions, or 46.6% of all upstream emissions, while total upstream emissions for the remaining 90% of natural gas supply account for about 4.3% of total emissions. Compared to the 100% conventional natural gas system, upstream emission for the production of Dutch gas are somewhat lower per kWh, because of the decreased amount of this Dutch gas used per kWh. When examining the emissions associated with the imported Russian natural gas, the main sources of emissions are methane emissions during transportation and the combustion of natural gas for transportation.

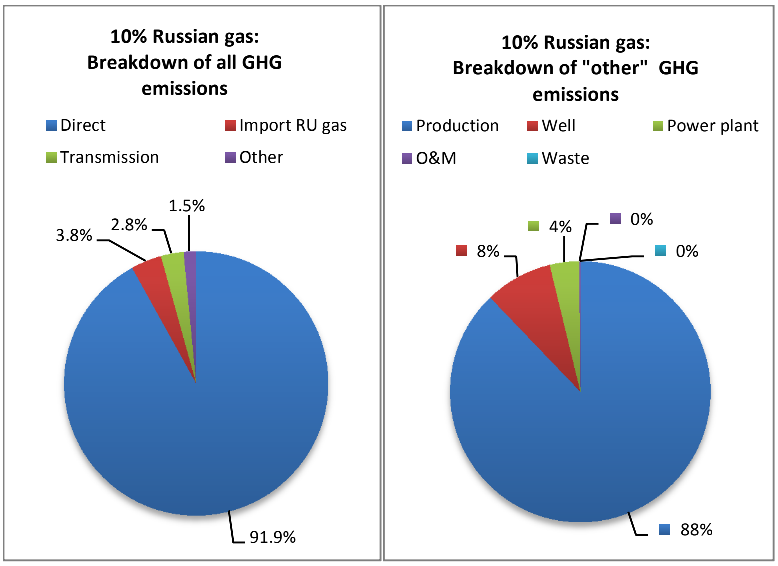


Figure 4.5: Breakdown of the GHG emissions of the 90% conventional natural gas + 10% Russian natural gas electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category "other" as shown left.

4.3. Shale gas

In Table 4.5 and Figure 4.6 below, a breakdown is shown of the GHG emissions of the shale gas system. As with the conventional gas system, the vast majority of emissions is released during combustion of the gas in the power plant. However, as total emissions for the shale gas system are somewhat higher, relatively, a smaller fraction of emissions are caused by direct emissions (91.2% vs. 95.2% for conventional natural gas). This is caused by an increase in upstream emissions.

Differences with the conventional natural gas system become more apparent when looking at upstream processes. The fraction of emissions from drilling and completion of the well increase to about 4.2%. Transportation emissions remain almost the same in absolute terms, but decrease relatively, due to the fact that shale gas is produced only onshore. Emissions released during hydraulic fracturing are relatively small, at nearly 0.2% of total GHG emissions per kWh of electricity. These emissions are primarily released by the combustion of diesel in the hydraulic pumps but do not include the high but uncertain methane emission estimates from flow back water by Howarth et al., 2011. Production and transportation of the used chemicals contribute the remainder of HF operation emissions, but do not contribute much to the overall result.

Table 4.5: Breakdown of the GHG emissions of the shale gas system per kWh of electricity generated

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Direct	442.26	91.18%
Transmission	14.15	2.92%
Production	7.05	1.45%
Well	20.45	4.22%
Hydraulic Fracturing	0.86	0.18%
Waste	0.0002	0.00%
Power plant	0.28	0.06%
O&M	0.013	0.00%
Total	**485.07**	**100.00%**

Methane emissions

Methane is released in almost all the processes in the shale gas cycle, as is the case with conventional natural gas. Most of the methane emissions are released during transmissions, production and from the well. In literature, there is not much known about specific methane emissions for shale gas wells. The research that is available is controversial and shows a significant difference between conventional gas wells and shale gas wells (Howarth et al., 2011). It is stated that especially from the water flowing back out of shale gas wells after HF operations large amounts of methane are released. In this section it is assumed here that methane emissions are not

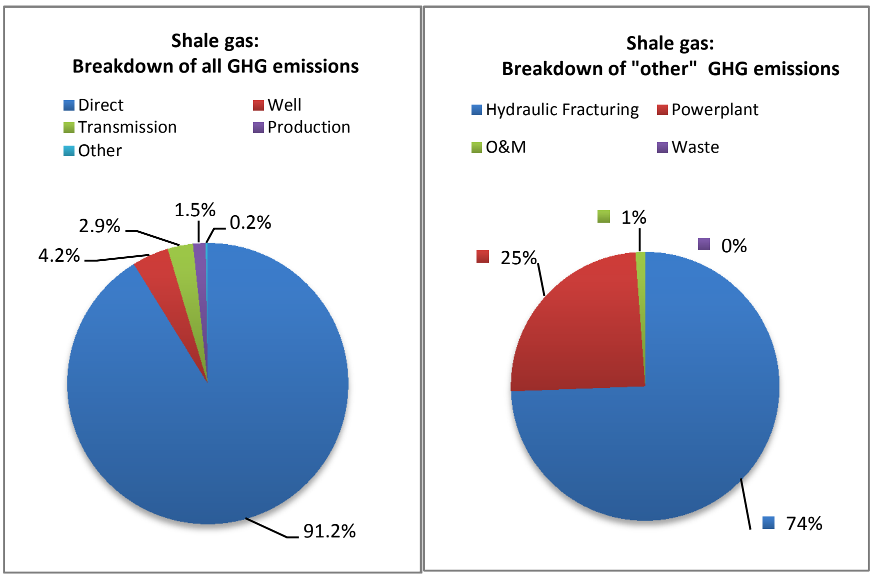


Figure 4.6: Breakdown of the GHG emissions of the shale gas electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category “other” as shown left.

different from conventional gas production, the results presented above for shale gas include emission estimates of methane released during conventional well completions. There are however indications that larger amounts of methane are released from shale gas wells compared to conventional wells (Armendariz, 2009; Howarth et al., 2011), although the precise amounts of methane emissions from shale gas wells is subject of some discussion (Jackson et al., 2011). To address the uncertainty in methane emissions from shale gas wells, the sensitivity analysis in section 5.2 will test the influence of this uncertainty range on the overall result. This uncertainty will also be discussed in section 6.2.

10% Shale scenario

To allow for a better comparison with the 10% LNG scenario, as well as to present a result for a more realistic shale gas use scenario for the short term, GHG emissions were analysed for a scenario in which 90% of the Dutch gas mix is CNG, and 10% in the Dutch gas mix is shale gas. The results of this scenario are presented below in Table 4.6 and Figure 4.7: Breakdown of the GHG emissions of the 90% conventional natural gas + 10% shale gas electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category "other" as shown left.. As expected, the emissions of this scenario are much lower than a 100% shale scenario, and only slightly higher than the 100% CNG scenario. Compared to the 10% LNG scenario, emissions are much lower. LNG liquefaction, transport, and processing for introduction (expansion) are much more energy intensive than the added effort required to extract shale gas.

Table 4.6: Breakdown of the GHG emissions of the 90% CNG + 10% shale gas system per kWh of electricity generated

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Direct	442.26	94.8%
Transmission	14.21	3.05%
Well	2.65	0.57%
Production	7.15	1.53%
Hydraulic Fracturing	0.09	0.02%
Waste	0.00	0.00%
Power plant	0.28	0.06%
O&M	0.01	0.00%
Total	**466.66**	**100.00%**

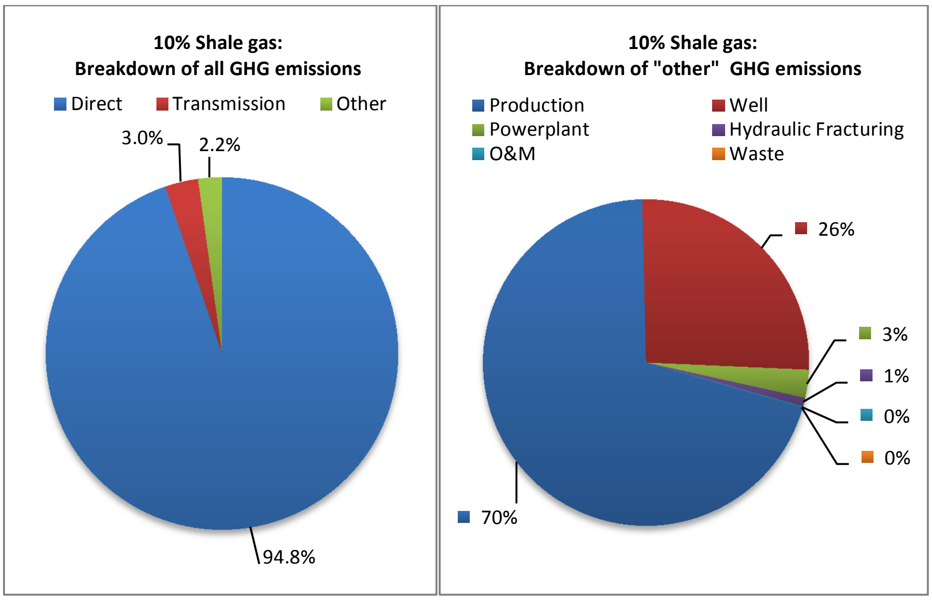


Figure 4.7: Breakdown of the GHG emissions of the 90% conventional natural gas + 10% shale gas electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category "other" as shown left.

4.4. Coal

Table 4.7 and Figure 4.8 below show a breakdown of GHG emissions released in the coal electricity system. Comparable with both natural gas systems described above, the majority of emissions (88.9%) is released in the power plant, through combustion of the coal. The transportation of coal from the various origins to the Netherlands causes about 60 grams of CO_2 equivalent emissions, or about 6% of total emissions, a slightly smaller fraction of emissions are released during production of the coal.

Table 4.7: Breakdown of the GHG emissions of the coal system per kWh of electricity generated

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Direct	875.27	88.9%
Transport	58.98	5.99%
Production	43.22	4.39%
Waste	5.46	0.55%
Power plant	1.74	0.18%
O&M	0.19	0.02%
Total	**984.86**	**100.00%**

Transportation emissions are released in various processes, but the majority of emissions come from the combustion of fuel oil for operation of the ocean freighter. Other emissions are released mainly during maintenance of the ocean freighters. Barge transportation within the Netherlands releases a relatively small amount of emissions per kWh of electricity compared to ocean freighter transportation.

About 56% of emissions released during production are caused by methane being released from the coal. Other emissions (about 41% of total production emissions) come from the input of energy (diesel, heat and electricity) and the production of the explosives used to blast rocks.

Power plant (including decommissioning) and operation and maintenance emissions only contribute to about 0.2% and 0.02%, respectively.

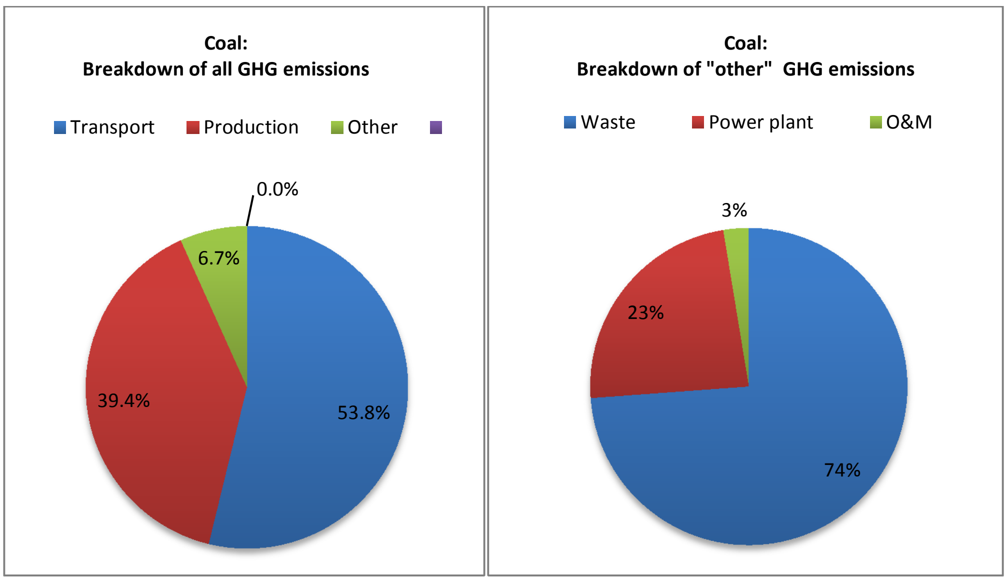


Figure 4.8: Breakdown of the GHG emissions of the coal electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category "other" as shown left.

4.5. Nuclear

Table 4.8 and Figure 4.9 below show a breakdown of GHG emissions released in the nuclear electricity system. The majority of emissions are released in the frontend of the nuclear cycle (59.1%) and the operation of the nuclear power plant (31.5%). Frontend emissions will be detailed further on in this section. Relatively small amounts of emissions are released in the construction of the power plant (4.7%) and the management of nuclear waste (backend; 3.4%) and decommissioning of the power plant (1.33%).

Table 4.8: Breakdown of the GHG emissions of the nuclear system; per kWh of electricity generated

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total emissions
Frontend	23.32	59.1%
Construction	1.85	4.69%
Operation	12.44	31.5%
Backend	1.35	3.43%
Decommissioning	0.52	1.33%
Total	**39.49**	**100.00%**

The frontend emissions are detailed in Table 4.9. From this table it shows that the frontend emissions are mainly composed of emissions released during the construction and operation of the ISL well field (almost 80%). Emissions of this process mainly come from diesel used to power drilling of the wells, and from the production of steel and high density polyethylene used for the wells and the supply injection fluids to the wells, respectively.

Table 4.9: Breakdown of the GHG emissions of the frontend of the nuclear system; per kWh of electricity generated

Emission source	GHG emissions (g CO_2-eq/kWh)	Percentage of total frontend emissions
ISL	18.44	79.1%
Conversion	3.12	13.4%
Enrichment	1.70	7.30%
Fuel Production	0.06	0.26%
Total frontend	**23.32**	**100.00%**

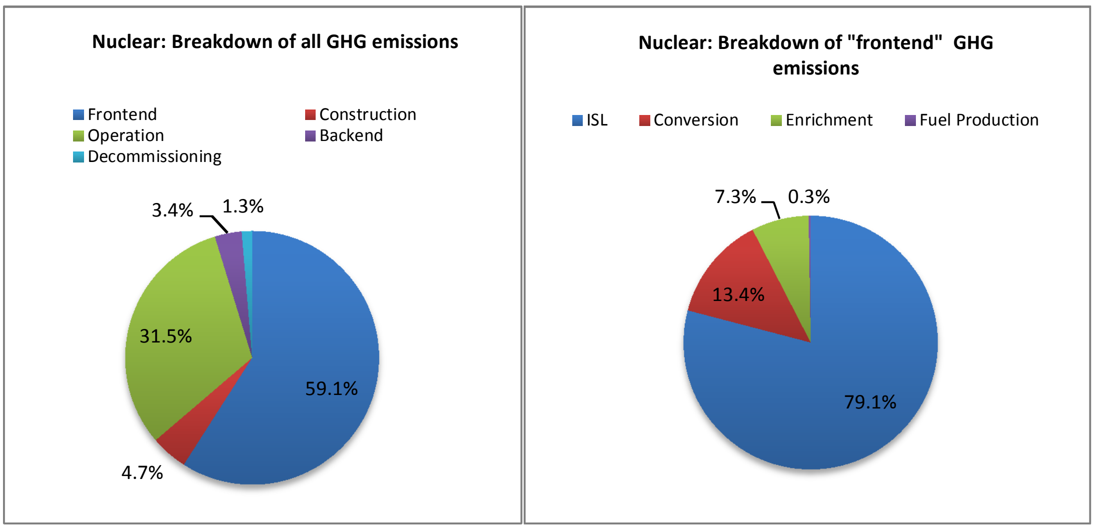


Figure 4.9: Breakdown of the GHG emissions of the nuclear electricity production system. Left: Breakdown of all emissions. Right: Breakdown of the emissions of the category "frontend" as shown left.

4.6. Wind – onshore

The GHG emissions per kWh of the onshore wind system are presented in Table 4.10 and Figure 4.7 (left). It is clear that the production of the moving parts of the turbine contributes most (68.4%) to the overall GHG emissions. Another major factor is the production and placement of the tower, accounting for almost 15.1% of total GHG emissions per kWh. Tower emissions include connection to the grid. All emission sources as mentioned in Table 4.10, except operation and maintenance, are fixed emission sources, e.g. they do not vary with electricity production. Therefore, the lifetime electricity production of turbines, determined by both the capacity factor and lifetime of the turbine itself, largely determines overall GHG emissions per kWh. As there is some variability in literature concerning capacity factors and lifetime of both moving parts and fixed parts (tower, foundation) section 5.4 will analyse the influence of varying capacity factors on the overall result.

Table 4.10: Breakdown of the GHG emissions of the onshore wind electricity system; per kWh of electricity generated.

Emission source	GHG emissions (gCO_2-eq/kWh)	Percentage of total emissions
Moving parts	8.18	68.42%
Tower	1.80	15.07%
Transportation	0.70	5.83%
Waste	0.53	4.44%
Foundation	0.66	5.52%
O&M	0.09	0.72%
Total	**11.95**	**100.00%**

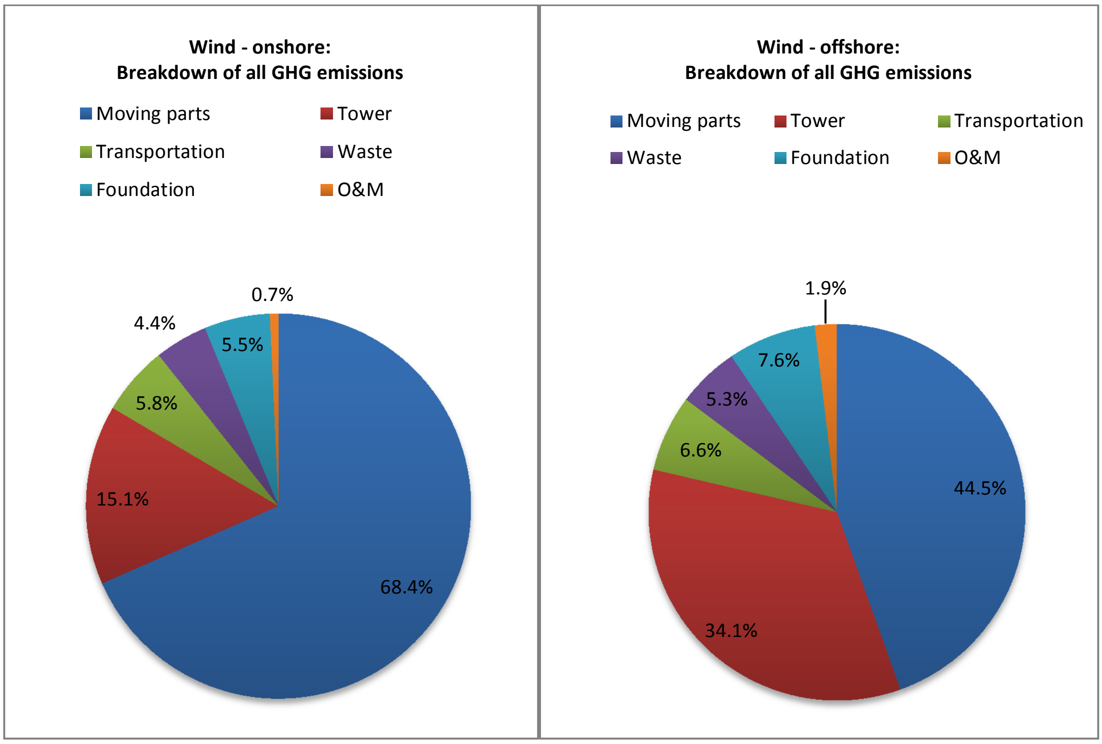


Figure 4.10: Breakdown of the GHG emissions of the two wind electricity production system. Left: Breakdown of all emissions for onshore wind turbines. Right: Breakdown of all emissions for offshore wind turbines.

4.7. Wind – offshore

The results for offshore wind electricity are quite similar overall to those for the onshore wind system, however, the distribution of emissions is somewhat different, and the overall result is slightly lower. The results are presented in Figure 4.10 (right graph) and Table 4.6. In total, 11.2 gCO_2-eq/kWh is released, making offshore wind the most environmentally friendly electricity generation option studied here (in terms of GHG emissions). All categories in the offshore wind electricity system have higher emissions compared to onshore wind, except for the moving parts. This is mainly due to the fact that offshore turbines have a higher capacity (37% vs. only 22% for onshore turbines) and thus produce much more electricity over their lifetime, which is equal to that of onshore turbines (for moving parts, foundation lifetime is twice as long for onshore turbines).

The lower emissions for the moving parts but higher emissions for other categories leads to a relative shift in distribution towards the latter, however, at 44.5% the majority of emissions is still released as a consequence of producing the moving parts. Tower emissions for offshore turbines include connection to the grid, as offshore turbines are situated some 20 kilometres from shore, these emissions are higher compared to onshore wind turbines and contribute more to the overall emissions. This is also caused by a shorter lifetime of the tower compared to onshore wind turbines.

Table 4.11: Breakdown of the GHG emissions of the offshore wind electricity system; per kWh of electricity generated.

Emission source	**GHG emissions (g CO_2-eq/kWh)**	**Percentage of total emissions**
Moving parts	4.99	44.53%
Tower	3.83	34.12%
Transportation	0.74	6.58%
Waste	0.60	5.32%
Foundation	0.85	7.56%
O&M	0.21	1.90%
Total	**11.21**	**100.00%**

4.8. Upstream emissions and supply mix scenarios

The goal of this section is to compare the production cycles of conventional natural gas to that of shale gas. In Figure 4.11 below, a comparison is presented of the upstream emissions of both systems. Also included are three previously mentioned mixed supply scenarios: one with 10% LNG, one with 10% Russian natural gas and one with 10% shale gas.

It is clear from the graph below that the difference in GHG emissions per MJ of gas, between CNG and shale gas is primarily caused by an increase in emissions from drilling and completion of the well. As mentioned before, this is mainly because shale gas wells are much less productive, and shale gas wells are generally longer, as they extend not only vertical, but also horizontal, typically for about 1.2km. Hydraulic fracturing is responsible for only a small increase in upstream emissions.

When comparing the three "mixed supply" scenarios it is obvious that, in terms of GHG emissions, domestically produced shale gas is preferred above importing LNG or Russian natural gas. The upstream emissions of both supply mixes of 90% GNG and 10% LNG or Russian gas are almost as high as the upstream emissions of the 100% shale gas system.

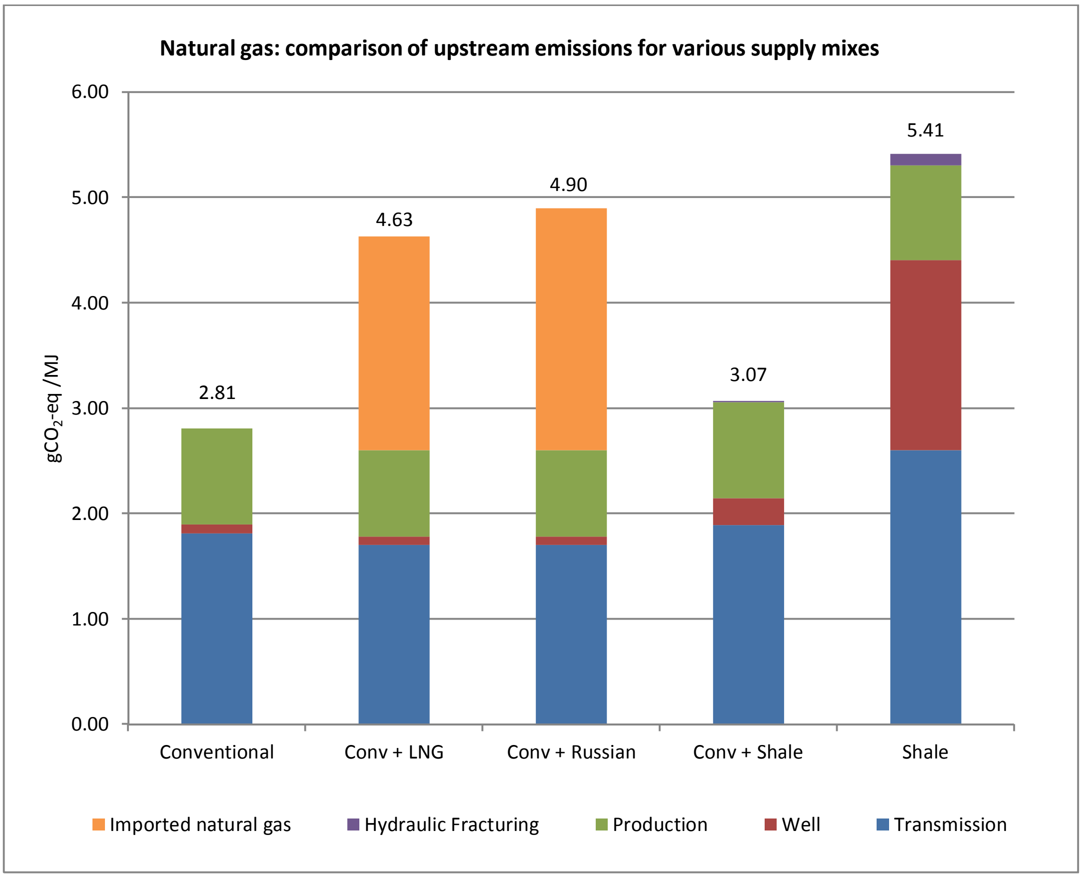


Figure 4.11: Comparison of the upstream emissions of four natural gas production scenarios. Data is presented per MJ of gas delivered to customer and thus includes production and transmission but not power plant construction. The sum of each column is presented on top. Conventional: Upstream emissions of 100% CNG supply. Conv + LNG: Upstream emissions of a supply mix of 90% Dutch CNG and 10% Algerian LNG. Conv + Russian: Upstream emissions of a supply mix of 90% Dutch CNG and 10% Russian CNG. Conv + Shale: Upstream emissions of a supply mix of 90% Dutch CNG and 10% Dutch Shale gas. Shale: Upstream emissions for 100% Dutch Shale gas.

5. Sensitivity analysis

This chapter will analyse various factors of each system to assess the influence a change in said factor would have on the overall result. A limited selection of factors was made; only factors were investigated here that are thought to have an important effect on the overall result when changed. In the graphs below, the overall result is plotted against the change in each parameter, expressed in percentage deviation from the original value. For instance, in section 5.1, the efficiency is ranged from about 40-60%, the original value is 46%, so the change in this parameter varies from -7.6% to +31%.

5.1. Natural gas

As can be seen in the previous chapter, the emissions for natural gas powered electricity production mainly come from the power plant, as a direct consequence of combustion of the natural gas. The main determinants of these direct emissions are (1) the emissions factor of natural gas (the amount of CO_2 release per MJ of natural gas burned) and (2) the amount of gas needed per unit of output electricity. The first of these is more or less fixed by physical properties of natural gas, but the latter varies based on the efficiency of power generation. In a review of Dutch power plants for the year 2004 (Seebregts & Volkers, 2005), the efficiency of Dutch natural gas fired power plants to is described to range between 39% and 53%. However, an even larger variety in efficiency can be obtained by changing the method to calculate it. As was mentioned before, a variety of approaches is used to calculate power plant efficiency and allocate emissions in the case of co-generation of heat and power (see section 2.1.1). Using the variety of approaches mentioned in the paper by Graus & Worrell, 2010, a range of efficiencies is obtained of about 40%-60%. Relative to the efficiency originally used (46%, LHV basis), this represents a change in efficiency ranging from -7.6% to +31%. When the efficiency is varied along this range in the calculations of the GHG emissions per kWh, the graph below is obtained (Figure 5.1; blue line). With this range, the overall emissions vary from about 356-503 gCO_2-eq/kWh with high and low efficiency respectively.

As we have seen in chapter 4, the size of gas fields or the lifetime production per well can have some influence on overall emissions. Especially considering the fact that the average exploration find in EBN partnerships has been decreasing during the last few years, it is useful to know how this would affect life cycle GHG emissions. As we can see from Figure 5.1, when the field size decreases by 75%, the emissions do increase, although slightly. A doubling of the field size (+100% change in parameter) leads to a small reduction in overall

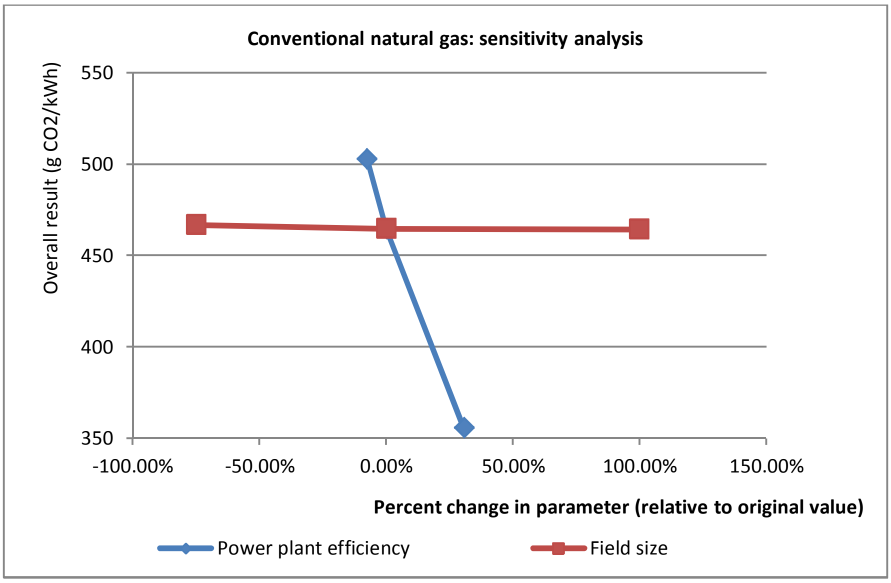


Figure 5.1: Sensitivity analysis for the conventional natural gas systems. The factors power plant efficiency and field size (or production per well) were varied and the influence on the overall result

GHG emissions.

From these analyses it can be concluded that if the sizes of newly discovered fields keep decreasing as they have been over the last years, the overall GHG emissions of the natural gas electricity system will increase by a small amount. This increase could however easily be negated by a very small increase in power plant efficiency.

5.2. Shale gas

For the shale gas electricity system, the same parameters were tested as for the conventional natural gas system. As shale gas can be combusted in the same power plants, the reasoning behind the analysis of power plant efficiency is the same as that mentioned in the previous section. Therefore, the same range of efficiencies is analysed. The analysis of field size is however based on a slightly different reasoning. As mentioned in section 3.2.1.1 there as of yet no production data on Dutch shale gas wells, and U.S. data shows a large variability in lifetime production per well. Ranges go from as low as 24 million m^3 to 104 m^3 (Wood et al., 2011) and average about 63-92 million m^3 per well (Berman, 2009). The first range was analysed and is presented below in Figure 5.2.

Another factor in shale gas production which is somewhat uncertain, is the amount of methane released during and especially after hydraulic fracturing. Few research has been conducted to assess these emissions specifically for shale gas wells, but one study available reports 1.6% of the total production from a shale gas well is leaked during flow back of hydraulic fracturing water (Howarth et al., 2011). However, this 1.6% of total production represents an amount that is some 6621% higher than what is assumed in this study. At this value, considered here as a "worst case scenario", the overall result increases by about 50 gCO_2-eq/kWh to about 535 gCO_2-eq/kWh. To make the graph below (Figure 5.2) more readable, a more or less arbitrary range going from zero methane emission from well completions to a 200% increase (three times the baseline emissions) is presented. With this smaller range, the overall result varies only slightly.

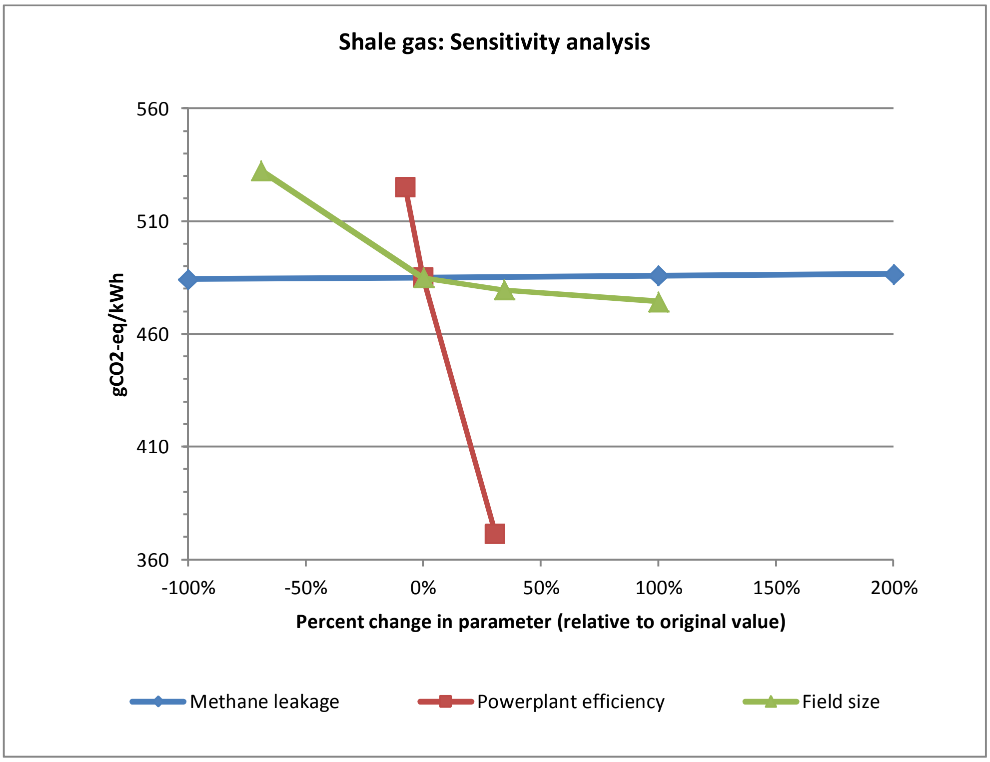


Figure 5.2: Sensitivity analysis for the shale gas systems. The parameters methane leakage, power plant efficiency and field size (or production per well) were varied and the influence on the overall result was tested. Note that the x-axis does not show the absolute value of the parameters but rather the change (expressed in per cent) of the parameter from the original value.

5.3. Coal

As with the various natural gas based systems, the GHG emissions of the coal system are largely determined by the direct emissions due to combustion of coal. Almost ninety per cent of overall emissions are released during this process. As was the case in the previous sections, the power plant efficiency is an important factor in determining the amount of fuel burned and thus the direct emissions per kWh of electricity. Based on the same variety of methods of calculating efficiency, coal power plant efficiency ranges from 37.4-44.2% (LHV basis). Another factor that has varied quite a bit in coal electricity in the Netherlands is the import mix of coal. As was shown in section 4.4, the emissions released during transport account for about 6% of overall emissions. When the import mix shifts, the overall distance an average kilogram of coal has to travel can obviously decrease or increase. When we look at the origin of Dutch coal, there are large differences between the distances of travel from the various countries our coal is coming from (see section 3.3.2). For this analysis, a range of transport distances was studied that varies from a minimum distance based on a mix from 2006 that has a relatively low average transport distance, to a maximum based on a mix that is coming from Australia only, the supplier that is furthest from the Netherlands.

As we can see in Figure 5.3 below, as expected, the efficiency of power generation has again a strong influence on overall GHG emissions per kWh. A reasonably small difference in efficiency causes a range of almost 160 gCO_2-eq/kWh when going from minimum to maximum efficiency. The transportation distance also has a marked effect on the overall result. If all coal would be transported by the maximum distance, overall emissions would increase to almost 1029 gCO_2-eq/kWh, whereas were it transported over shorter distance as was observed a few years ago, emissions would decrease to about 973 gCO_2-eq/kWh.

As it is not clear if all the waste of coal power plant operations can be recycled in the future, the influence of the recycling percentage on the overall result was also analysed. If none of the waste is recycled (100% landfilled), emissions increase with about 0.04%. This very small increase the result is not presented in the graph below.

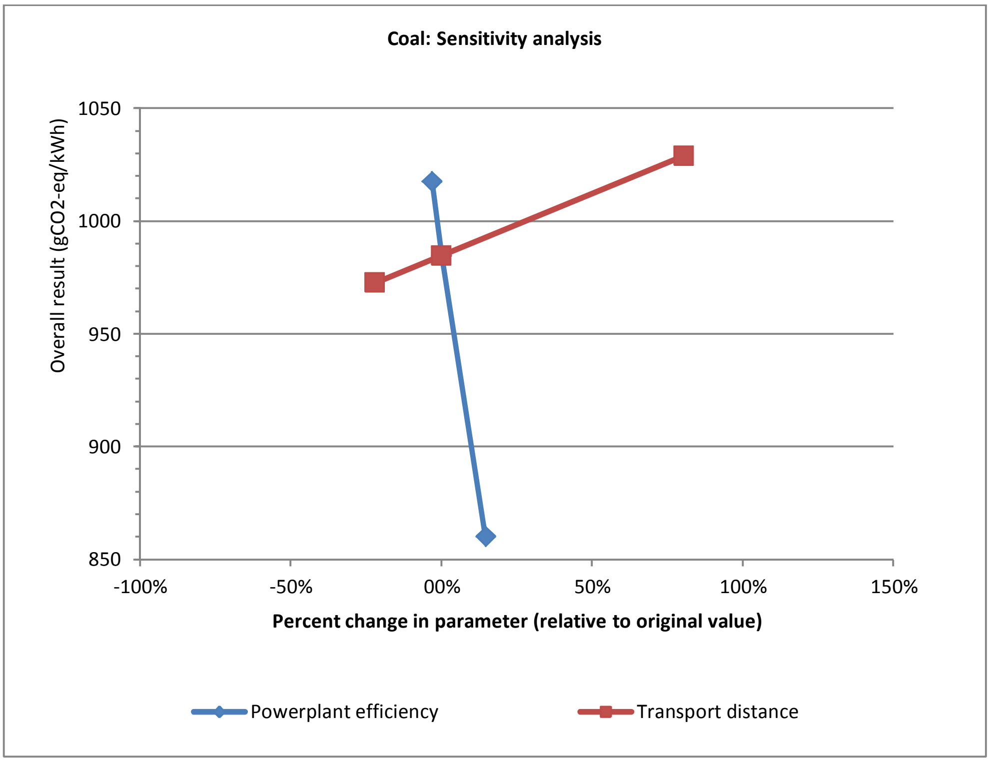
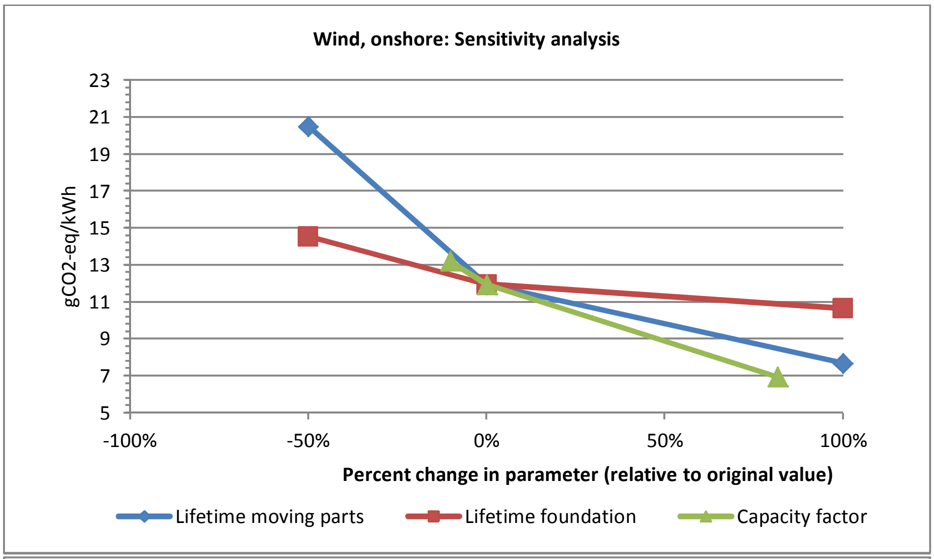


Figure 5.3: Sensitivity analysis for coal. The parameters power plant efficiency and transport distance were varied and their influence on the overall result was analysed. Note that the x-axis does not show the absolute value of the parameters but rather the change (expressed in per cent) of the parameter from the original value.

5.4. Wind – onshore and offshore

Wind energy is fundamentally different from fossil fuel fired electricity, mainly because the requirements of producing wind electricity are mostly fixed, e.g. not varying with the amount of electricity produced. Some factors do vary according to the amount of electricity produced indirectly, like maintenance, but major factors in the overall GHG emissions are due to fixed requirements, such as the production of parts and the construction of the wind turbine. From this, and when looking at the equation from section 2.1, where life cycle emission were defined roughly as total emissions divided by total electricity production, it follows that the amount of GHG emissions per kWh for a specific turbine can only vary when the lifetime electricity production varies. This production is determined by three factors: The capacity factor, the lifetime of the turbine, and the capacity of the turbine.

In literature, a variety of capacity factors is assumed for wind energy. The values in this study were based on average data for actual production versus installed capacity for the Netherlands, but within this data, there is a reasonably large variation. The lower and upper boundaries for capacity factor were taken from the lowest and highest measured capacity factor from a selection of wind turbines operated by Eneco (Eneco B.V., 2011b). For onshore turbines, the CF varies from 19.8% to 40%, and for offshore turbines from 33.3% to 41.4%.



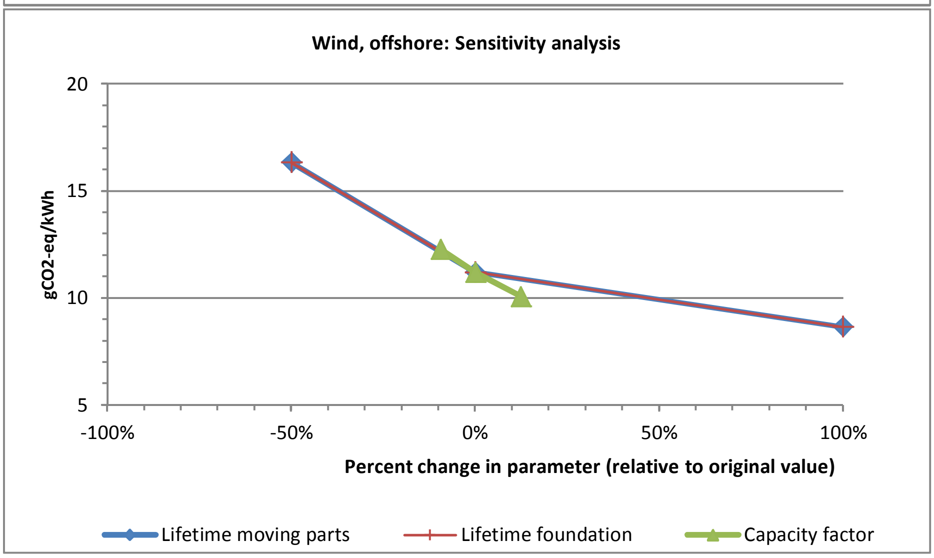


Figure 5.4: Sensitivity analysis for onshore (top) and offshore (bottom) wind electricity for the parameters lifetime (of both moving and fixed parts) and capacity factor. Note that the x-axes do not show the absolute value of the parameters but rather the change (expressed in per cent) of the parameter from the original value.

For the lifetime an arbitrary range of lifetimes was chosen for both offshore and onshore turbines. For onshore turbines, the "normal" lifetime is 20 years for the moving parts and 40 years for the foundation and tower (fixed parts). For offshore turbines, normal lifetime of both fixed and moving parts was assumed to be 20 years, based on Vestas, 2006a; Vestas, 2006b; Ecoinvent Centre, 2007. For all these lifetimes a range was made from -50% to +100%. Especially the upper band of this range does not represent realistic assumptions for lifetime of turbines on a short to medium term but is primarily meant to offer insight in de dependency of the overall result on the lifetime of various parts of the turbines.

The results of the sensitivity analysis for wind energy systems are presented in Figure 5.4. Please note that scale of these graphs is much smaller compared to the figures in the previous section. As expected, increase in lifetime and capacity factor results in a large *relative* decrease of overall emissions. However, absolutely, the over result only changes by a small amount of gCO_2-eq/kWh compared to tens of gCO_2-eq/kWh as observed for the fossil fuels (as seen in sections 5.1-5.3). When examining these graphs it appears as though the capacity factor has more influence on the overall result compared to the lifetime of the various parts. In itself, this is true but it is mainly due to the fact that the lifetime parameters were analysed separately for fixed and moving parts, e.g. when the lifetime for moving parts was varied, the lifetime for fixed parts was kept constant and vice versa. When changing the capacity factor, as a consequence, the emissions for both moving and fixed parts increase. Fixed parts include the tower and the foundation, this explains why the effect of a change in lifetime is similar for moving vs. fixed parts, as the emissions for the moving parts are almost equal to the emissions for the tower and foundation combined.

5.5. Nuclear

As mentioned before throughout section 3.5, analyses of nuclear energy systems show enormous variation in the overall GHG emissions per kWh of electricity. In a review by Sovacool, 2008 of many LCA studies on nuclear electricity, a range is reported of 1.4 to 288 gCO_2-eq/kWh. As discussed before in section 3.5, this variation is partly caused by different methods being used to calculate emissions, but there are more factors that could contribute to the difference between these studies.

First of all, there are several mining methods for uranium, each with its own requirements. The commonly used techniques of opencast and subsurface mining are studied commonly, but another technique, studied here is ISL mining. The requirements for ISL in this study were based on only one source, as little research is available about this mining technique. The main determinant of ISL mining is the amount of uranium produced from an ISL mining field. ISL field lifetime production was varied between arbitrarily chosen boundaries of -50% to +100% of the production given in SRK Consulting Inc., 2010 that was used in this study. As shown in Figure 5.5 (bottom, blue line), a range emission from about 35-50 gCO_2-eq/kWh is obtained when the lifetime production is varied from -50% to =100% of the value used in the main result of this study.

In enrichment of uranium, more differences arise. The most commonly used enrichment techniques are gaseous diffusion and centrifuge enrichment. Gaseous diffusion requires about 30 to 60 times more electricity per unit of enriched uranium. Because of this large difference, enrichment was included in the sensitivity analysis below. The upper boundary was chosen to be the requirement for gaseous diffusion enrichment, the lower boundary was set at the electricity requirement for the most efficient enrichment plants. These are 50% more efficient compared to the Russian enrichment plants included in this study which need 80 kWh/kgSWU[t]. Enrichment energy input was varied from 40 kWh/kgSWU (-50%), which is the energy requirement in modern, western enrichment facilities to 2500 kWh/kgSWU (+3025%), which is the requirement for gaseous diffusion facilities.

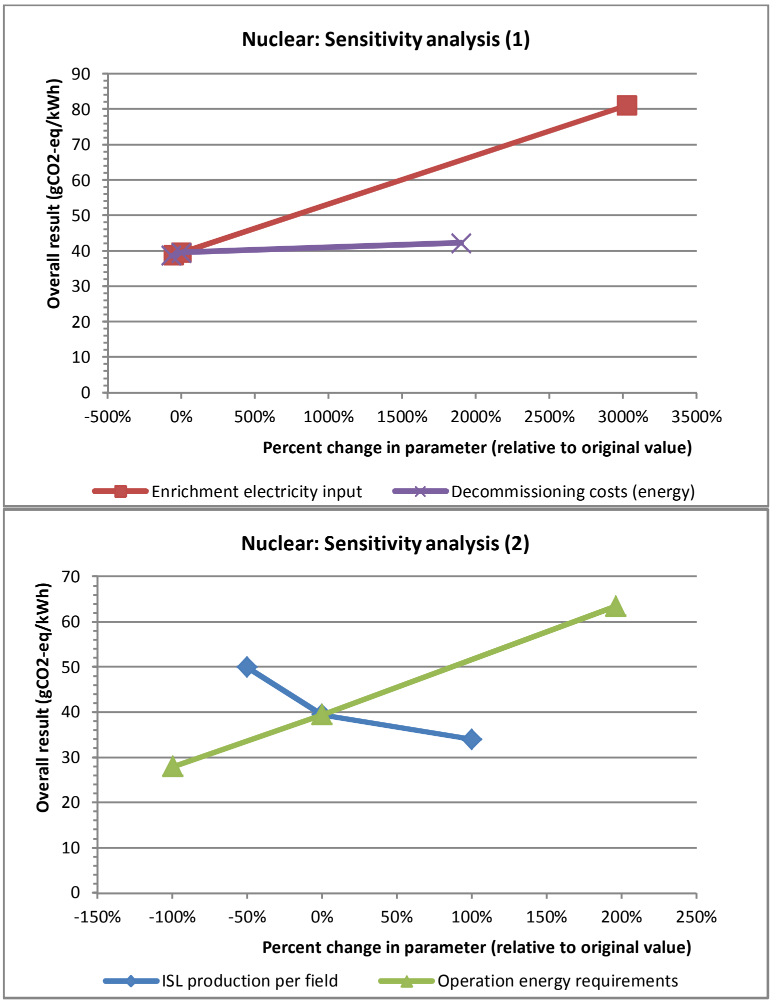


Figure 5.5: Sensitivity analysis for the nuclear electricity system. Top: sensitivity analysis for the parameters enrichment electricity input and decommissioning costs (energy). Bottom: sensitivity analysis for the parameters ISL field production and operation energy requirements. Note that the x-axis does not show the absolute value of the parameters but rather the change (expressed in per cent) of the parameter from the original value.

[t] SWU = Separative Work Unit. A separative work unit is a unit that defines the amount of work that a centrifuge cascade needs to perform in order to enrich uranium. The amount of SWU needed is defined by the mass of feed uranium, and the percentage of uranium-235 in the feed, product (enrichment grade) and the tails (tails assay) (Lenzen, 2008).

A main factor in the overall results presented in section 4.5 is the energy input during operation of the nuclear power plant. For these requirements, again, large ranges are being reported of almost zero energy input to almost double the value used in this study (Lenzen, 2008). This range was tested and presented in Figure 5.5.

Yet another factor that shows large variation in literature is the energy required for decommissioning of nuclear power plants. Values are reported of about 3% to 200% of the energy required for construction of the same power plant (Lenzen, 2008). In the main results of this study, an average value of 10% was assumed based on the same study by Lenzen. This 10% is the value that is used in most studies reviewed in the study by Lenzen, 2008. Because of the range reported, the decommissioning energy requirement was varied from -70% to +1900% of the original value.

6. Discussion

6.1. Conventional natural gas

Natural gas has been deemed the least GHG intensive fossil fuel available for a long time and in many studies. This study further confirms this point. However, especially since the enormous increase in U.S. domestic natural gas production, questions have been raised about the GHG footprint of natural gas production activities, mainly focusing on methane emissions from wells and transmission equipment. Significant methane emissions could dramatically increase the GHG emissions of natural gas production, as methane is a very potent GHG compared to CO_2.

The methane emissions figures used in this study are much lower compared to figures coming from Russia or the United States (Lelieveld et al., 2005). However, the values used here are based on independently verified data from production and transmission companies (NAM, 2007; Gasunie, 2010b) and aside from this fact, there are large differences between the Russian and the Dutch gas transmission, as the latter is much smaller in comparison (Lelieveld et al., 2005) and the amount of leakage is for a large part dependent on the distance the gas is transported (Ecoinvent Centre, 2007). Furthermore, even emission figures from Russia that are much higher compared to the Dutch figures used in this study would still make natural gas the fossil fuel with the lowest overall GHG emissions (Lelieveld et al., 2005).

With the large Dutch gas fields depleting in the coming decades, there is also a shift from wells with large lifetime production, to smaller wells. This will lead to a relative increase in GHG emissions and could increase the overall GHG footprint of natural gas fired electricity in the Netherlands. However, as established in section 5.1, the well lifetime production, when varying within realistic boundaries, does not strongly influence the overall GHG footprint of natural gas fired electricity. Only in fields that are almost twenty times smaller compared to the average conventional gas find per well, emissions increase by only 5% based on total GHG footprint of NG fired electricity production (established by comparing with shale gas results).

Emissions of the combined natural gas mix could very much increase if the fraction of LNG in the supply mix increases. With only ten per cent of LNG in the supply mix, emissions increase by 3% per kWh of electricity. Were this fraction to increase further, say to twenty per cent, emissions would increase with 6% relative to 100% conventional natural gas to 492 gCO_2-eq/kWh. Similar results are obtained when instead of LNG, Russian conventional natural gas is imported. With 10% of total supply coming from Russia, emissions increase with 3.5%.

The results of this study largely agree with previous studies on the emissions of natural gas fired electricity. In a review of several studies (Dones et al., 2007) found the GHG emissions per kWh of natural gas fired electricity to be about 400 to 600 gCO_2-eq/kWh. Differences are largely based on power plant efficiency. For instance, data in the Ecoinvent database for the Netherlands show much higher figures than calculated in this study, at over 580 gCO_2-eq/kWh. However, this is based on a power plant efficiency of only 34%, compared to the 46% used in this study (both on LHV basis). These efficiencies were calculated with the same method, only the latter was calculated with newer data.

6.2. Shale Gas

The majority of the shale gas cycle is equal to the conventional natural gas cycle. Differences occur only during the first stages of production, with well drilling and completion and hydraulic fracturing. However, as average production from shale gas wells over their lifetime is much lower, upstream emissions increase significantly, and become largely based on the well activities, much less on the addition of hydraulic fracturing. Both are the subject of some discussion in recent research though. First, well lifetime production varies

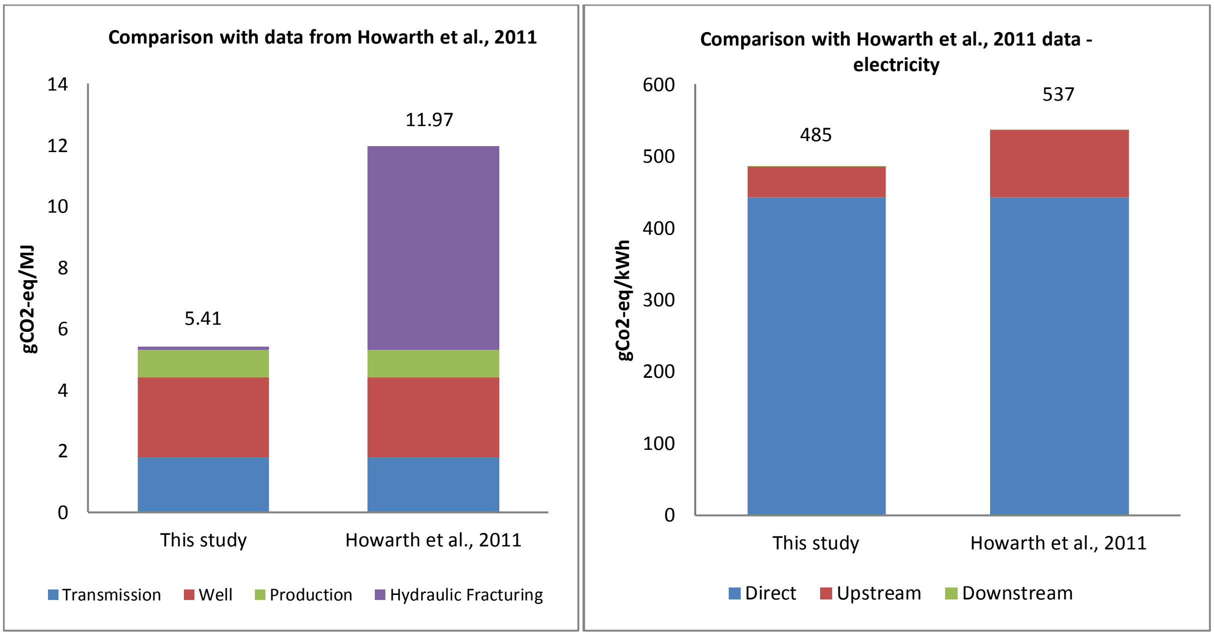


Figure 6.1: Comparison of the results of this study compared to the results if the flow back methane emissions figures from Howarth et al, 2011 are used. Figure presents the GHG emissions of shale gas production, expressed per MJ of gas produced (left) and the GHG emissions per kWh of electricity (right).

much per shale formation, with ranges being reported of about 20 to over 100 million cubic meters per well. As seen in section 5.2, at the low end of this range, emissions would be clearly higher. It is not yet known what average wells would produce in the Netherlands, but is seems safe to say that the lower limit is determined by economics. There is already some doubt about the economic viability of shale gas production in the U.S., so it would seem illogical to produce shale gas from even smaller wells. If shale gas wells in the Netherlands would be *more* productive compared to American wells, the overall GHG emissions would slowly approach values for conventional natural gas production.

Aside from well lifetime production, there is uncertainty on the subject of methane emissions from completed shale gas wells. It is argued that large amounts of methane are released especially from the flow back water after hydraulic fracturing, up to 1.6% of total lifetime production of natural gas per well (Howarth et al., 2011). Howarth's study is one of the few studies focusing specifically on methane emissions from shale gas wells. However, the results of this study have been received with some doubt. The data sources quoted in this study cannot be verified. The figures presented in the study are almost 100 times higher than what is estimated currently for conventional gas wells in the Netherlands. If the large methane emission figures of Howarth et al. are included, overall GHG emissions of shale gas production increase to about 537 gCO_2-eq/kWh. A 200% increase of well methane emissions (as analysed in section 5.2) only increases overall GHG emission to 487 gCO_2-eq/kWh. This latter value is not based on research on methane emissions but was mainly calculated to show how a small (compared to Howarth et al., 2011) increase in methane emissions would change the overall result. From these different results it becomes clear that further analyses should focus on these emissions after hydraulic fracturing, to reduce the variation in the overall result and to establish values specific for the Netherlands.

The GHG emissions of shale gas fired electricity or shale gas production have not been studied much. The study by Howarth et al., 2011 presents significantly different results compared to this study, and reports GHG emissions per MJ of fuel in the range of about 23-30 gram carbon per megajoule (81-109 gCO_2-eq/MJ) for shale and about 29 gram carbon per megajoule (98 gCO_2-eq/MJ) for coal. This does however not include conversion to electricity in a power plant. Howarth et al. state that this conversion would not alter the result significantly; however, when the efficiencies used in this study are applied (39% for coal power plants, 46% for natural gas) coal does have the highest GHG emissions per kWh. Furthermore, the study by Howarth uses a GWP[u] for methane that is different (higher) than the value established by the IPCC in 2007, commonly used in such studies. In Figure 6.1, the difference is shown between the results of the study by Howarth et al. and this study for the production of shale gas. In this figure, methane emission data from Howarth was included, but converted to CO_2-eq emissions with the GWP as defined by the IPCC.

In another study, Wood et al. 2011 analyse the additional CO_2 equivalent emissions per megajoule of shale gas compared to a megajoule of conventional gas. They find that including hydraulic fracturing operations and increased well length, GHG emissions of shale gas production amount to 57.14 - 58.63 gCO_2-eq/MJ compared to 57 gCO_2-eq/MJ for conventional gas and 93 gCO_2/MJ for coal. Wood et al. conclude that although shale gas production emissions will be higher compared to conventional natural gas, "*they are unlikely to be markedly so*" and mention that the difference between coal and the two natural gas variants further increases when considering power plant efficiency. Wood et al. furthermore conclude that the main determinant in GHG emissions per unit of energy of extracted shale gas is the lifetime production per well, as is concluded from this study as well.

6.3. Coal

Many studies available today support the findings of this study that coal is indeed one of the most GHG intensive energy carriers. The main cause of these high emissions is the fact that during combustion of coal, large amount of CO_2 are released. However, in this study, indirect emissions contribute over 10% of total emissions. This also leads to some uncertainty in the overall result.

The main contributors of indirect emissions are the emissions released during transport of coal via ocean freighters, and methane emissions released during mining. Of course, transport emissions are heavily dependent on the distance the coal is transported. Methane emissions vary significantly per country (Bibler et al., 1998). It is however not precisely known where the coal used in the Netherlands is coming from, and thus the distance it is transported is not precisely known. The electricity companies in the Netherlands are not required to report the origin of the coal they burn, so the data used in this study was based on a report by (VDKi, 2009) which presents data that is not specific for the mix of coal burned in Dutch power plants. Rather, a mix of all the hard coal being imported into the Netherlands is given. This also includes coal destined for export from the Netherlands to other European countries, and some coal not imported to be combusted for electricity generation. A report by Greenpeace from 2008 shows roughly the same import mix as used in this study, however, a more recent annual report shows a large shift in the import mix towards import from Colombia (VDKi, 2010). In 2009, almost sixty per cent of the coal imported in the Netherlands came from Colombia, compared to 28% per cent in 2008. However, total import did not increase, especially from South-Africa and Indonesia, much less coal was imported. Methane emissions per kg of coal are relatively low in Colombia compared to the other countries. Therefore, with the current import mix, GHG emissions associated with the production of coal are currently relatively low. A shift of the import mix away from mainly Colombian coal could therefore increase overall GHG emissions.

In the sensitivity analysis on the transport distance (see section 5.3), it is shown that the overall result does varies markedly when the import distance is increased or decreased based on the shift in mix mentioned above. Analysis of the Ecoinvent database furthermore shows that a shift in the supply mix could also change overall methane emissions. Especially Colombian coal mines emit much less methane compared to other regions, while South-African mines have the highest methane emissions of all the countries included here (Ecoinvent Centre, 2007). The influence of the import mix on the overall result is however bound by two factors, both upwards and downwards. If the emissions of coal production and transport decrease, the value of the overall emissions approaches the emissions

[u] GWP = Global Warming Potential. The GWP describes the global warming effect of different greenhouse gases relative to the effect of CO_2 and is used to mathematically convert emissions of other greenhouse gases to CO_2 equivalent emissions. Commonly, for methane, a GWP of 25 gCO_2-eq/gCH_4 is used, to describe the effect of methane in the atmosphere for a period of 100 years.

value of direct and downstream emissions combined. When assessing all of the countries where the coal used in the Netherlands has originated from, lowest emissions per kg coal are released for Colombian coal. If all the coal would come from Colombia, the import mix will have the lowest possible emissions, given the data used and not including possible other coal origins. In this case, coal production and transport emissions would still contribute to the overall result, but the relative contribution of direct emissions would increase. If all coal is imported from the country with highest emissions for production and transport, the value would increase, but be bound by the specific emissions of this country and the transport distance.

6.4. Wind

The emissions of wind powered electricity heavily rely on the fixed emissions released by producing the wind turbines. The lifetime electricity production of a wind turbine therefore determines the overall emissions per unit of electricity produced. Two factors determine the lifetime electricity production, namely the capacity factor, and the lifetime of various parts of the wind turbine. In this study, the capacity factor was taken as an average of current wind production in the Netherlands, specified for onshore and offshore production. As weather in general and wind conditions vary locally, the capacity factor could vary significantly per location. The specific location of a wind turbine could therefore be of great influence on the overall emissions. Optimal wind conditions are not necessarily the first determinant in locating a wind turbine, as conditions have to be met regarding wildlife and the local population. However, on average it is reasonable to assume wind turbines could reach at least the current average capacity factor. Furthermore, newly developed wind turbines are able to operate at a broader variety of wind speeds, possibly increasing their relative electricity production.

The lifetime of the various parts of a wind turbine also have a large relative influence on the overall emissions. As direct emissions are very low, an increase in lifetime could very much lower the overall emission of wind electricity. As we have seen in section 5.4, the GHG emissions range from 7.7-20.5 gCO_2-eq/kWh and 8.6-16.3 gCO_2-eq/kWh for onshore and offshore respectively, when the lifetimes of the various parts is varied from -50% to +100% of the original value used in this study.

Another factor with some influence on the overall GHG emissions per kWh is the distance to the electricity grid. With increasing distance, as can be seen by comparing the onshore vs. offshore turbines studied here, the emissions released as a consequence of the materials and activities required for the connection to the grid increase. Onshore grid connection in this study is based on an average distance in Europe from turbine to grid, but offshore grid distance is based on the two existing offshore wind farms in the Netherlands. In other countries, wind farms can be situated much closer to shore, resulting in a decrease of emissions associated with grid connection (Ecoinvent Centre, 2007).

The life cycle GHG emissions of wind powered electricity have been studied extensively. In a review of over 50 LCA's on wind electricity, a range of GHG emissions was found of 7.9-123.7 gCO_2/kWh, for wind turbines with capacities varying from 0.3 kW to 3 MW, and capacity factors varying from 7.6-50.4% (Lenzen & Munksgaard, 2002). The study furthermore found that the energy intensity of wind electricity (input energy per output kWh of electricity) decreases when the capacity of the wind turbine increases. As mentioned before in the introduction, total energy demand is a good proxy for GHG emissions in LCA's (Huijbregts et al., 2006). These findings seem to corroborate the findings of this study. A selection of newer literature on life cycle GHG emissions presents reasonably similar results, with GHG emission per kilowatthour ranging from 9.7-16.5 GCO_2-eq/kWh (Jungbluth et al., 2005; Ardente et al., 2008; Varun & Prakash, 2009).

6.5. Nuclear

The nuclear electricity system is both widely discussed in literature and public opinion, but is also the system with the least consensus on GHG emissions. In literature, a very broad range of emissions per kWh is being reported, ranging from 1.4-288 gCO_2-eq/kWh. For a large part, this range can be explained by the variety of methods employed to calculate the life cycle emissions. Furthermore, there is a variety of methods for mining and enrichment of uranium, each with their own consequence in terms of GHG emissions. There is however a general agreement that nuclear electricity results in lower emissions compared to electricity created by combustion of fossil fuels.

In this study, there are several factors that show some uncertainty and that could have a large influence on the overall result. In general, the nuclear fuel cycle is not well documented, and emissions data and energy use data often rely heavily on assumptions or small selections of data. The emissions released due to ISL mining for instance, are based on one report and are calculated with the assumption that the technology employed is similar to that of oil well drilling. On one hand this could lead to an overstatement of emissions, on the other hand, the model of the ISL well field included in this study leaves out some inputs as no suitable data could be found.

When comparing the results of this study with other research, it can be concluded that the values reported in this study are somewhat lower than the average found in literature. In a survey of 103 lifecycle studies of nuclear electricity, an average of 66 gCO_2-eq/kWh was found (Sovacool, 2008). There are several possible explanations to explain this difference. As mentioned before, a variety of methods is used to calculate life cycle GHG emissions. LCA's using process analysis, as this study does, generally result in lower emissions results compared to those using Input-Output analysis. Aside from the methodology of these analyses, differences also occur because the nuclear cycle is slightly or highly different per country or even per nuclear reactor. For instance, the uranium used in the Dutch reactor is mined in Kazakhstan via ISL mining and is enriched in Russia via centrifuge enrichment to an enrichment grade of 4.45%. Other cycles include a different method of mining, a different origin, a different method of enrichment and a different enrichment grade. Enrichment via gaseous diffusion for instance has much higher energy requirements of about 2400-2600 kWh/kgSWU compared to only 40-80 kWh/kgSWU for centrifuge enrichment. If only part of the uranium is enriched via gaseous diffusion, overall emissions can increase significantly and could approach the average as found by Sovacool.

When examining the averages obtained by Sovacool it furthermore becomes clear that the main differences with the studies analysed there arise because of differences in emissions for construction and decommissioning of the power plant, as well as for waste management processes at the end of the fuel cycle. Many of the studies reviewed employ I/O analysis to analyse construction and decommissioning emissions, whereas this study does not calculate emissions based on the monetary value, but rather examines the materials and energy required to build and demolish the power plant. Emissions for the frontend of the cycle and operation of the power plant are very similar to those found in Sovacool, 2008. However, the variation in decommissioning emissions is likely also related to the fact that there is as of yet very little experience with decommissioning of nuclear power plants. The results of this study are based on the amount of nuclear waste generated and the amount of energy used to construct a typical nuclear power plant. As construction requirements as calculated in this study are relatively low compared to the overall result, the variation caused by the uncertainty in decommissioning emissions as studied in section 5.5 is small. However, if decommissioning operation turn out to be more comprehensive and less dependent on the material and energy input of construction than is assumed here, emissions could increase.

7. Conclusions

A variety of factors has led to an increase in interest for shale gas production in Europe and the Netherlands. Globally, the demand for natural gas is expected to rise significantly in the coming years, prompting a look for alternatives supplies. For the Netherlands specifically, this search could be slightly more urgent. Natural gas production has been one of the major factors contributing to state income and allowing for a relatively high standard of living in the Netherlands. Since the discovery of the large gas field near Slochteren in the north of the Netherlands, large amounts of gas were produced, and a significant fraction of domestically produced gas is exported to other European countries. However, at current consumption rates, the conventional gas reserves in the Netherlands will last for about 20 more years.

Shale gas resources in the Netherlands have been estimated to hold up to several times the gas initially in place in the Slochteren gas field. However, as shale gas extraction requires hydraulic fracturing of the shales, concerns have risen about the environmental impacts of shale gas production. These concerns cover a variety of topics, initially predominantly concerning drinking water contamination and other forms of pollution, but more recently concerns have risen about the emissions of greenhouse gases from shale gas production. Few studies have yet been released that assess these emissions, but some think they could be significantly higher than those released during conventional natural gas production and combustion.

Shale gas, when produced, is essentially the same substance as conventional gas. Therefore it would seem logical that the main applications of shale gas will lie in the substitution of conventional natural gas in its main application. Currently, in the Netherlands, the main applications of conventional natural gas are electricity production and direct use. The latter category can be divided in industrial use (for instance in ammonia production or use in furnaces) and domestic use, predominantly for space heating and cooking. If of sufficient quality, shale gas could directly and partly substitute conventional natural gas in these areas.

Alternatives to the use of either CNG of Shale gas are mainly found in electricity production. Currently, about 60% of Dutch electricity is produced with natural gas. For direct use, alternatives are not widely used or available. Only space heating and cooking are commonly performed powered by electricity. In electricity production, alternatives to CNG currently used in the Netherlands are (by order of their percentage in the total Dutch electricity supply):

- Coal fired electricity
- Wind power
- Nuclear power

The extraction of shale gas in the Netherlands was modelled according to experience in shale gas production in the United States. The energy and material requirements of the shale gas production cycle share large similarities with that of CNG, however in the overall result, large differences occur due to various factors:

First and most importantly, U.S. experience has shown that shale gas wells are much less productive compared to CNG wells. Current CNG wells in the Netherlands produce about 1.5 billion cubic meters, while average American shale gas wells produce only 62-93 million cubic meters, both over their full lifetime, i.e. one Groningen well is as productive as about 20 shale gas wells. While this does not lead to an absolute increase in emissions, it leads to a relative increase in emissions as the same amount of energy and materials are used to produce much less gas. Furthermore, to increase productivity of shale gas wells, most current wells are drilled first vertically, and are deviated horizontally at target depth. This increases drilling requirement and associated emissions.

Secondly, shale gas production requires an increased effort, based on several factors. As shale gas is found in layers of rock with low permeability, extraction requires hydraulic fracturing of this rock. During hydraulic fracturing, diesel engines are used to pump water, proppant[v] and a selection of chemicals into a newly completed well. Production and transport of these materials add a small amount of CO_2-eq emissions to the overall result, but most of the emissions released during hydraulic fracturing are released due to the combustion of diesel in the aforementioned pumps. When looking at the overall result however, hydraulic fracturing only releases 0.2% of total emissions.

When considering the various forms and mixes of natural gas, and examining the GHG emissions per megajoule of produced and delivered gas, it is clear that both the 100% shale gas supply and the 90% CNG + 10% LNG supply have much higher emissions compared to a supply of 100% CNG from the Netherlands. The same holds for a mix of 90% CNG and 10% Russian natural gas, although slightly higher compared to the LNG scenario. A supply mix that contains only 10% of shale gas with 90% of CNG has only a small amount of increased GHG emissions per MJ of natural gas, thus much lower emissions compared to the 10% LNG mix. The main difference between shale gas production and CNG production is caused by relatively increased emissions from drilling and completion of the well caused by a decrease in well lifetime production. The increase in emissions of the 10% LNG supply is mainly caused by the high emissions from the transport of the LNG and the liquefaction and evaporation required for this transport. The high emissions for Russian gas are mainly caused by methane leakage and energy use during long-distance transportation of the natural gas.

This increase in emissions in the production cycle of shale gas logically increases the overall emissions per kWh when looking at electricity production. Compared to CNG, using 100% shale gas will increase emissions from about 465 gCO_2-eq/kWh to about 485 gCO_2-eq/kWh, or an increase of about 4.4%. Compared to a scenario that includes the import of 10% of LNG produced in Algeria, shale gas emissions are only 1% higher. In a scenario where instead of 10% LNG, 10% of shale gas is used in a mix with 90% CNG, emissions are only 0.44% higher compared to 100% CNG at 467 gCO_2-eq/kWh. Compared to the 10% LNG scenario, these emissions are 2.9% lower. Emissions of a scenario with 10% of the Dutch supply coming from Russia again are similar, but slightly higher compared to the LNG scenario.

Compared to other alternatives in electricity production, shale gas emissions are quite similar to those for CNG, as the difference with the studied alternatives is quite large. The highest CO_2-eq emissions in this study are released by coal fired electricity production system at 985 g/kWh. Nuclear and wind have much lower CO_2-eq emissions compared to the fossil fuels, at 39.3 g/kWh for nuclear electricity and 11.9 g/kWh for onshore wind and 11.2 g/kWh for offshore wind electricity.

In the full cycle of shale gas production there are two factors that can have a large influence on the overall result and for which data is limited and uncertain: the lifetime production per shale gas well and the amount of methane release after hydraulic fracturing operations. When examining both factors from their minimum to their maximum values, a large range in the overall result is obtained. With a low lifetime production or with high methane emissions after hydraulic fracturing, overall emissions increase substantially compared to the main result of this study. Further research on the GHG of the shale gas lifecycle should focus on these two factors to reduce the uncertainty in the overall result.

For the studied fossil fuels, most CO_2-eq emissions are released in the power plant, due to combustion of the fuels. Percentages of emissions released in this phase vary from 89% of total emissions for coal, 91% for shale gas, 92% for CNG + 10% LNG, to 95% for CNG. The two other alternatives (nuclear and wind) have much smaller emissions during electricity production as the main fuel or

[v] Proppant is a granular material (commonly sand) used in hydraulic fracturing to prevent the fractures from closing after they are formed.

energy source is not combusted. Nuclear energy does have a high fraction of direct emissions though due to the combustion of diesel in backup and safety generators required for cooling and managing the power plant.

When comparing the fossil fuels, it is obvious that the biggest difference between the three gas based scenarios and the coal system occur in the electricity production phase. As coal has a much higher emission factor compared to natural gas (be it shale, LNG or CNG) and coal power plants are of lower efficiency compared to gas fired power plant, direct emissions for coal are almost twice as high compared to natural gas. Furthermore, mainly because of transportation requirements for coal, upstream emissions are much higher. Production of coal is also more emission intensive compared to natural gas. Combustion of coal also results in significant amounts of solid and gaseous waste, requiring disposal or reuse and treatment of flue gases, respectively.

The fossil fuel systems of this study are difficult to compare with the other two systems, nuclear and wind. However, it is clear that the difference in emissions between the fossil systems on the one hand and the other systems is mainly due to the fact that the latter systems have almost no or small amounts of direct emissions. Relative to the other energy systems, wind energy has relatively high emissions related to construction of the "power plant". This is mainly due to the fact that wind turbines are of much lower capacity, have a much lower capacity factor, and to a lesser extent because their lifetime is shorter, compared to the power plants of the other electricity systems. This results in wind turbines producing much less energy relative to the construction requirements. However, emissions are still very low due to the fact that there are almost no direct emissions.

References

Ardente, F., M. Beccali, M. Cellura, and V. Lo Brano , 2008. Energy performances and life cycle assessment of an Italian wind farm. Renewable and Sustainable Energy Reviews, vol. 12, pp. 200-217.

Areva, 2011. EPR™ reactor, on of the most powerful in the world, Areva, Paris, France. http://www.areva.com/EN/global-offer-419/epr-reactor-one-of-the-most-powerful-in-the-world.html, Retrieved on: 2011/03/22.

Armendariz, A. , 2009. Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, Department of Environmental and Civil Engineering, Southern Methodist Universtity, Dallas, Texas, US.

Arthur, J. D., B. Bohm, B. J. Coughlin, and M. Layne, 2008. Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs, , ALL Consulting.

Baumann, H., and A. M. Tillman, 2004. The Hitch Hiker's Guide to LCA. An orientation in life cycle assessment methodology and application. Studentlitteratur, Lund, Sweden.

Berman, A., 2009. Lessons from the Barnett Shale suggest caution in other shale plays. World Oil Magazine.

Bibler, C. J., J. S. Marshall, and R. C. Pilcher , 1998. Status of worldwide coal mine methane emissions and use. International Journal of Coal Geology, vol. 35, pp. 283-310.

Blok, K., 2007. Introduction to energy analysis. Techne Press, Amsterdam, The Netherlands.

Cantor, R., and J. Hewlett , 1988. The economics of nuclear power : Further evidence on learning, economies of scale, and regulatory effects. Resources and Energy, vol. 10, pp. 315-335.

Centraal Bureau voor de Statistiek, 2010. CBS Statline - Energiebalans, kerncijfers, The Hague / Heerlen, The Netherlands. http://statline.cbs.nl/StatWeb/publication/?VW=T&DM=SLNL&PA=37281&D1=a,!1,!4&D2=a&D3=0,20,33,(l-5)-l&HD=101208-1038&HDR=T&STB=G1, Retrieved on: 2010/12/08.

Centraal Bureau voor de Statistiek, 2011. CBS Statline - Windenergie; elektriciteitsproductie, capaciteit en windaanbod per maand, Centraal Bureau voor de Statistiek, The Hague / Heerlen, The Netherlands. http://statline.cbs.nl/StatWeb/publication/?DM=SLNL&PA=70802NED&D1=0-1,3&D2=a&D3=118,135-149&HDR=T&STB=G1,G2&VW=T, Retrieved on: 2011/02/22.

Delta Energy B.V., 2009. Startnotitie milieueffectrapport tweede kerncentrale Borssele, Delta Energy B.V., Middelburg, The Netherlands.

Dones, R., 2005. Life Cycle Inventories for the Nuclear and Natural Gas Energy Systems, and Examples of Uncertainty Analysis. The International Journal of Life Cycle Assessment, vol. 10, pp. 10-23.

Dones, R., C. Bauer, R. Bolliger, B. Burger, M. Faist Emmenegger, R. Frischknecht, T. Heck, N. Jungbluth, A. Röder, and M. Tuchschmid, 2007. Life cycle inventories of energy systems: results for current systems in Switzerland and other UCTE countries. Ecoinvent Report, vol. 5,.

D'Souza, N., E. Gbegbaje-Das, and P. Shonfield (2011), Life Cycle Assessment of Electricity Production from a V112 Turbine Wind Plant, , PE North West Europe ApS, Copenhagen, Denmark.

Ecoinvent Centre, 2007. Ecoinvent data v2.0. Ecoinvent reports No. 1-25, , Swiss Centre for Life Cycle Inventories, Dübendorf, Switzerland.

Eneco B.V., 2011a. Princess Amalia Wind Farm - Project Details, Eneco B.V., Rotterdam, The Netherlands. http://www.prinsesamaliawindpark.eu/en/windpark.asp, Retrieved on: 2011/03/22.

Eneco B.V., 2011b. Windenergieprojecten, Eneco B.V., Rotterdam, The Netherlands. http://wind.eneco.nl/eneco_en_windenergie/windenergie_projecten/Pages/Default.aspx, Retrieved on: 2011/03/22.

Energie Beheer Nederland B.V., 2010. Focus on Dutch Gas | 2010, , Energie Beheer Nederland B.V., Utrecht, The Netherlands.

Energy Resources Holding B.V., 2010. Mededeling van het voornemen tot de bouw van: een nieuwe kerncentrale voor Energy Resources Holding B.V. op de locatie Borssele te Zeeland.

EPZ, 2010a. Milieueffectrapportage brandstofdiversificatie, Elektriciteits-productiemaatschappij Zuid-Nederland N.V., Borssele, The Netherlands.

EPZ, 2010b. De oorsprong van EPZ's uranium, Elektriciteits-productiemaatschappij Zuid-Nederland N.V., Borssele, The Netherlands. http://www.epz.nl/content.asp?kid=10031520&fid=1&bid=10034721, Retrieved on: 2010/12/07.

EST, 2011. Shale Gas I: The future of shale gas in Europe, European Student Think Thank, Amsterdam, The Netherlands. http://studentthinktank.eu/blogs/the-future-of-shale-gas-in-europe/, Retrieved on: 2011/05/30.

GasTerra, 2011. Jaarverslag - Maatschappelijk verslag - 2010, GasTerra B.V., Groningen, the Netherlands.

Gasunie, 2010a. Jaarverslag 2009, N.V. Nederlandse Gasunie, Groningen, The Netherlands.

Gasunie, 2010b. M.V.O. Jaarverslag 2009, N.V. Nederlandse Gasunie, Groningen, The Netherlands.

Gasunie, 2011. Jaarverslag 2010, N.V. Nederlandse Gasunie, Groningen, The Netherlands.

Graus, W., and E. Worrell, 2010. Methods for calculating CO2 intensity of power generation and consumption: A global perspective. Energy Policy.

Guinée, J. B., 2002. Handbook on life cycle assessment, Operational guide to the ISO standards. Kluwer Academic Publishers, Dordrecht, The Netherlands.

GWPC and ALL Consulting, 2009. Modern Shale Gas Development in the United States: A Primer, U.S. Department of Energy.

Herber, R., and J. De Jager, 2010. Oil and Gas in the Netherlands - Is there a future? Netherlands Journal of Geosciences - Geologie en Mijnbouw, vol. 89, pp. 119-135.

Hondo, H., 2005. Life cycle GHG emission analysis of power generation systems: Japanese case. Energy, vol. 30, pp. 2042-2056.

Howarth, R. W., 2010. Preliminary assessment of the greenhouse gas emissions from natural gas obtained by hydraulic fracturing. Cornell University, New York, USA.

Howarth, R. W., R. Santoro, and A. Ingraffea , 2011. Methane and the greenhouse-gas footprint of natural gas from shale formations. Climatic Change, pp. 1-12.

Huijbregts, M. A. J., L. J. A. Rombouts, S. Hellweg, R. Frischknecht, A. J. Hendriks, D. van de Meent, A. M. J. Ragas, L. Reijnders, and J. Struijs, 2006. Is cumulative fossil energy demand a useful indicator for the environmental performance of products? Environmental Science & Technology, vol. 40, pp. 641-648.

IEA, 2010a. Energy Statistics - Coal statistics for Netherlands, International Energy Agency, Paris, France. http://iea.org/stats/coaldata.asp?COUNTRY_CODE=NL, Retrieved on: 2011/03/14.

IEA, 2010b. Energy Statistics - Electricity for The Netherlands, International Energy Agency, Paris, France. http://www.iea.org/stats/electricitydata.asp?COUNTRY_CODE=NL, Retrieved on: 2010/12/08.

IEA, 2010c. Energy Statistics - Natural Gas for The Netherlands, International Energy Agency, Paris, France. http://www.iea.org/stats/gasdata.asp?COUNTRY_CODE=NL, Retrieved on: 2010/11/23.

IEA, 2010d. World Energy Outlook 2010, International Energy Agency, Paris, France.

Jackson, R. B., B. Rainey Pearson, S. G. Osborn, N. R. Warner, and A. Vengosh, 2011. Research and Policy Recommendations for Hydraulic Fracturing and Shale Gas Extraction. Center on Global Change, Duke University, Durham, NC, United States.

Jacobson, M. Z., and M. A. Delucchi, 2010. Providing all global energy with wind, water, and solar power, Part I: Technologies, energy resources, quantities and areas of infrastructure, and materials. Energy Policy, .

Jungbluth, N., C. Bauer, R. Dones, and R. Frischknecht, 2005. Life cycle assessment for emerging technologies: case studies for photovoltaic and wind power. International Journal of Life Cycle Assessment, vol. 10, pp. 24-34.

Kazatomprom, 2008. Uranium mining | Kazatomprom, http://www.kazatomprom.kz/en/pages/Uranium_Mining, Retrieved on: 2011/01/13.

Lelieveld, J., S. Lechtenböhmer, S. S. Assonov, C. A. M. Brenninkmeijer, C. Dienst, M. Fischedick, and T. Hanke, 2005. Greenhouse gases: Low methane leakage from gas pipelines. Nature, vol. 434, pp. 841-842.

Lenzen, M., 2008. Life cycle energy and greenhouse gas emissions of nuclear energy: A review. Energy conversion and management, vol. 49, pp. 2178-2199.

Lenzen, M., and J. Munksgaard, 2002. Energy and CO2 life-cycle analyses of wind turbines--review and applications. Renewable Energy, vol. 26, pp. 339-362.

Marshall, J. M., and P. Navarro, 1991. Costs of nuclear power plant construction: theory and new evidence. The Rand journal of economics, pp. 148-154.

Ministerie van Economische Zaken, 2010. Delfstoffen en Aardwarmte in Nederland, Jaarverslag 2009. Ministry of Economic Affairs, The Hague, Netherlands.

Ministerie van Economische Zaken, Landbouw en Innovatie, 2011. Wat is een kerncentrale en zijn er kerncentrales in Nederland? | Rijksoverheid.nl. Ministry of Economic Affairs, Agriculture and Innovation, The Hague, the Netherlands.

Mudd, G. M., 2001. Critical review of acid in situ leach uranium mining: 2. Soviet Block and Asia. Environmental Geology, vol. 41, pp. 404-416.

NAM, 2002. Maatschappelijk Verslag 2001. Nederlandse Aardolie Maatschappij B.V., Assen, The Netherlands.

NAM, 2007. Maatschappelijk Verslag 2006. Nederlandse Aardolie Maatschappij B.V., Assen, The Netherlands.

New York State, 2009. Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program. New York State Department of Environmental Conservation, Albany, NY, USA.

NoordzeeWind, 2010. NoordzeeWind Operations Report 2009. NoordzeeWind, IJmuiden, The Netherlands.

Osborn, S. G., A. Vengosh, N. R. Warner, and R. B. Jackson, 2011. Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. Proceedings of the National Academy of Sciences, vol. 108, pp. 8172.

Pachauri, R. K., A. Reisinger, and Intergovernmental Panel on Climate Change, 2007. Climate Change 2007: Synthesis Report. IPCC Secretariat, Geneva, Switzerland.

Pehnt, M., M. Oeser, and D. J. Swider , 2008. Consequential environmental system analysis of expected offshore wind electricity production in Germany. Energy, vol. 33, pp. 747-759.

Platform Nieuw Gas , 2007. Vol gas vooruit! De rol van groen gas in de Nederlandse energiehuishouding, EnergieTransitie, Utrecht, the Netherlands.

Pleizier, B., J. Bohm, and M. J. Brolsma, 2011. GasUnie "verliezen". Personal communications.

PRé Consultants, 2006. SimaPro 7 Multi User.

Rice, G., R. Clift, and R. Burns , 1997. Comparison of currently available European LCA software. The International Journal of Life Cycle Assessment, vol. 2, pp. 53-59.

Rosen, M.A., M.N. Lee and I. Dincer, 2005. Efficiency analysis of a cogeneration and district energy system. Applied Thermal Engineering, vol. 25 issue 1, pp. 147-159.

Scheepers, M. J. J., A. J. Seebregts, P. Lako, F. J. Blom, and F. van Gemert, 2007. Fact finding kernenergie, Energy research Centre of the Netherlands, Petten, The Netherlands.

Seebregts, A. J., and C. H. Volkers, 2005. Monitoring Nederlandse elektriciteitscentrales 2000-2004. ECN Beleidsstudies, Energy Research Centre of the Netherlands, Petten, the Netherlands.

SenterNovem Uitvoering Afvalbeheer, 2009. Nederlands afval in cijfers: gegevens 2000-2007, SenterNovem, Utrecht, the Netherlands.

Sokka, L., S. Koskela, and J. Seppälä, 2005. Life cycle inventory analysis of hard coal based electricity generation, , 952 pp., Finnish Environment Institute, Helsinki, Finland.

Solomon, S., 2007. Climate Change 2007: The Physical Science Basis. Cambridge University Press, Cambridge, UK.

Sovacool, B. K., 2008. Valuing the greenhouse gas emissions from nuclear power: A critical survey. Energy Policy, vol. 36, pp. 2950-2963.

SRK Consulting Inc., 2010. Powertech Uranium Corp. NI43-101 Preliminary Assessment - Dewey Burdock Project, Powertech Uranium Corp., Greenwood Village, CO, United States.

Storm van Leeuwen, J. W. , 2008. Nuclear power - the energy balance, Ceedata Consultancy, Chaam, The Netherlands.

Swigchem, J., H. J. Croezen, L. J. Kortmann, and F. J. Rooijers, 2005. Energiebesparing in de Nederlandse aardgasketen, verkenning naar besparingspotentieel en ketenafhankelijkheid, CE, Delft, the Netherlands.

US EPA, 2010. Hydraulic Fracturing Research Study - Background. United States Environmental Protection Agency, Washington, US.

Varun, I. K., and R. Prakash, 2009. LCA of renewable energy for electricity generation systems – A review. Renewable and Sustainable Energy Reviews, vol. 13, pp. 1067-1073.

VDKi, 2009. Annual report 2009: Facts and trends 2008/2009. Verein der Kohlenimporteure, Hamburg, Germany.

VDKi, 2010. Annual report 2010: Facts and trends 2009/2010. Verein der Kohlenimporteure, Hamburg, Germany.

Vestas, 2006a. Life cycle assessment of electricity produced from onshore sited wind power plants based on Vestas V82-1.65 MW turbines, , Vestas Wind Systems A/S, Randers, Denmark.

Vestas, 2006b. Life cycle assessment of offshore and onshore sited wind power plants based on Vestas V90-3.0 MW turbines, , Vestas Wind Systems A/S, Randers, Denmark.

Vidas, H., and B. Hugman, 2008. Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies, , The INGAA Foundation, Inc.

Voorspools, K. R., E. A. Brouwers, and W. D. D'Haeseleer, 2000. Energy content and indirect greenhouse gas emissions embedded in 'emission-free' power plants: results for the Low Countries. Applied Energy, vol. 67, pp. 307-330.

Weisser, D., 2007. A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies. Energy, vol. 32, pp. 1543-1559.

Westinghouse, 2011. Westinghouse AP1000, Westinghouse Electric Company LLC, Cranberry Township, PA, United States. http://www.ap1000.westinghousenuclear.com/ap1000_glance.html, Retrieved on: 2011/03/22.

Wood, R., P. Gilbert, M. Sharmina, K. Anderson, A. Footitt, S. Glynn, and F. Nicholls (2011), Shale gas: a provisional assessment of climate change and environmental impacts, , Tyndall Centre for Climate Change Research, University of Manchester, Manchester, UK.

World Nuclear Association, 2010a. Transport of Radioactive Materials, World Nuclear Association, London, UK. http://www.world-nuclear.org/info/inf20.html, Retrieved on: 2011/01/26.

World Nuclear Association, 2010b. WNA Public Information Service, World Nuclear Association, London, UK. http://www.world-nuclear.org/infomap.aspx, Retrieved on: 2011/01/12.

World Nuclear Association, 2011. In Situ Leach (ISL) Mining of Uranium, World Nuclear Association, London, UK. http://www.world-nuclear.org/info/inf27.html, Retrieved on: 2011/06/08.

Appendix 1: Equations and Calculations on CHP and SWU

A.1. Efficiency of co-generation power plants

The efficiency of power plants producing both electricity and heat (η_{ex}) is calculated with the following formula:

$$\eta_{ex} = \frac{E + \left[1 - \frac{T_{environment}}{T_{H,U} - T_{H,L}} \cdot \ln\left(\frac{T_{H,U}}{T_{H,L}}\right)\right] \cdot H_{CHP}}{F} \quad (3)$$

Where E is the total amount of electricity produced (TJ), H_{CHP} is the total amount of heat produced in CHP plants (TJ), F is the total fuel input (TJ), $T_{H,U}$ is the upper and $T_{H,L}$ is the lower temperature (K) of the heat produced and $T_{environment}$ is the temperature of the environment to which the heat is 'exposed'. The assumption is made that $T_{H,U}$ = 363 K, $T_{H,L}$ = 333 K and $T_{environment}$ is 283 K (= 10°C ≈ average annual temperature in the Netherlands). The upper and lower temperature of the heat is based on (Rosen et al, 2005) and other assumptions throughout literature on district heating temperatures. Other input data on electricity and heat production is taken from IEA, 2010c and IEA, 2010a.

The concept of exergy

The equation above is based on the concept of exergy. The concept of exergy allows us to deal with the fact that some forms of energy are more "useful" than others (Blok, 2007). For instance, 1MJ of electricity can be converted to 1MJ of heat, but it is not possible to convert 1MJ of heat into 1MJ of electricity. This is because the amount of work that can be extracted from heat is limited by the temperature of the environment, as work is extracted from heat when a heat source comes into equilibrium with its surroundings. Theoretically, the exergy content, or maximum amount of work from a heat reservoir (for instance, hot water) is given by the equation below (Blok, 2007):

$$B = \left[1 - \frac{T_{environment}}{T_{H,U} - T_{H,L}} \cdot \ln\left(\frac{T_{H,U}}{T_{H,L}}\right)\right] \cdot Q_{heatsource} \quad (4)$$

Where B is the exergy content of the heat source, and Q is the energy of the heat source. With the temperatures mentioned above, it follows that the exergy content of hot water of 90°C is only about 19% of its energy content. As electricity *is* work, by definition, its exergy content is equal to its energy content (Blok, 2007).

A.2. Separative Work Unit

The separative work unit is defined by the following formula:

$$SWU = PV(x_p) + TV(x_t) - FV(x_f) \quad (5)$$

where P, T, and F are the masses of product, tails and feed respectively, x_p, x_t and x_f are the uranium-235 concentrations in product, tails and feed respectively (called assays), and $V(x)$ is the value function (Lenzen, 2008):

$$V(x) = (1 - 2x)\ln\left(\frac{1-x}{x}\right) \quad (6)$$

The feed-to-product and tails-to-product ratio are determined by the assays of feed, product and tails and are defined by the following formulas:

$$\frac{F}{P} = \frac{x_p - x_t}{x_f - x_t}$$
$$\frac{T}{P} = \frac{x_p - x_f}{x_f - x_t} \qquad (7)$$

From these equations it follows that the amount of SWU required enriching 1 kg of uranium increases with: a) the enrichment concentration x_p; and b) a decrease in the tails assay. In this study, a natural U-235 concentration of 0.71%, a tails assay of 0.26% and an enrichment grade of 4.45% was assumed, requiring about 6.67 kgSWU/kg U_3O_8. However, including losses during enrichment this value increases to about 6.74 kgSWU/kg U_3O_8.