Multiregional environmental comparison of fossil fuel power generation – assessment of the contribution of fugitive emissions from conventional and unconventional fossil resources

Evert A. Bouman[a], Andrea Ramirez[b], Edgar G. Hertwich[a]

[a]Industrial Ecology Program, Department of Energy and Process Engineering, Norwegian University of Science and Technology (NTNU) NO-7491, Sem Sælandsveg 7, Trondheim, Norway.

[b]Energy & Resources, Copernicus Institute of Sustainable Development, Utrecht University, Heidelberglaan 2, 3584 CS, Utrecht, The Netherlands

Corresponding author:
Evert A. Bouman
Industrial Ecology Program, Department of Energy and Process Engineering, Norwegian University of Science and Technology (NTNU)
NO-7491 Trondheim, Norway
evert.bouman@ntnu.no

ABSTRACT

In this paper we investigate the influence of fugitive methane emissions from coal, natural gas, and shale gas extraction on the greenhouse gas (GHG) impacts of fossil fuel power generation through its life cycle. A multiregional hybridized life cycle assessment (LCA) model is used to evaluate several electricity generation technologies with and without carbon dioxide capture and storage. Based on data from the UNFCCC and other literature sources, it is shown that methane emissions from fossil fuel production vary more widely than commonly acknowledged in the LCA literature. This high variability, together with regional disparity in methane emissions, points to the existence of both significant uncertainty and natural variability. The results indicate that the impact of fugitive methane emissions can be significant, ranging from 3 % to 56 % of total impacts depending on type of technology and region. Total GHG emissions, in CO_2-eq./kWh, vary considerably according to the region of the power plant, plant type, and the choice of associated fugitive methane emissions, with values as low as 0.08 kg CO_2-eq./kWh and as high as 1.52 kg CO_2-eq./kWh. The variability indicates significant opportunities for controlling methane emissions from fuel chains.

Keywords: Carbon dioxide capture and storage; Life Cycle Assessment; fugitive emissions; coal; natural gas; electricity generation

1. INTRODUCTION

With the increasing interest in power generation from unconventional fossil fuel resources, such as shale gas, and the large push for gas fired power plants as a clean form of electricity production (Stephenson et al., 2012), a more complete quantification of the (potential) environmental impacts of fossil fuel power generation life cycle is needed. Though the environmental impacts of the operation of most power generation technologies are relatively well described and quantified in Life Cycle Assessment (LCA) literature (Corsten et al., 2013; Heath et al., 2014; O'Donoughue et al., 2014; Whitaker et al., 2012), we argue here that attention should also be directed towards upstream processes, such as the extraction and transport of fossil fuel resources (Alvarez et al., 2012; Burnham et al., 2012; Weber and Clavin, 2012). The fuel supply is especially important when carbon dioxide capture and storage (CCS) technology is applied to reduce the greenhouse gas emissions of the power plant itself, a step which increases fuel consumption due to the inherent energy efficiency penalty related to the carbon dioxide capture and compression processes.

One of the major greenhouse gases (GHGs) emitted in natural gas and coal production is methane. As a major constituent of natural gas, methane emissions occur at all points during the natural gas extraction process: well drilling and completion, well operation, e.g. in the form of purges and vents, and through leakages of the entire natural gas infrastructure, e.g., at intermediate compressor and redistribution stations of the pipeline (Burnham et al., 2012). Coal bed methane is formed from bacterial degradation of coal and biomass residuals, and thermally through devolatilisation within the coalification process of organic matter (Moore, 2012). It is released during coal extraction and removal of overburden. Methane emissions from fossil fuel origin are estimated to represent about 30% of the world anthropogenic methane emissions, although both fossil emissions and total anthropogenic emissions are quite uncertain (Kirschke et al., 2013).

A range of life cycle assessments (LCAs) of fossil fuel power generation with and without CCS has been published previously (Jaramillo et al., 2007; Koornneef et al., 2008; NETL, 2010b, c, d, e; Odeh and Cockerill, 2008; Singh et al., 2011a; Zapp et al., 2012). Most studies were thoroughly reviewed in the papers by Whitaker et al. (2012), O'Donoughue et al. (2014), Heath et al. (2014), and Corsten et al. (2013). Whitaker et al. (2012) present a review and harmonization of LCA greenhouse gas emission results for coal based electricity generation. Coal methane emissions are discussed, and an interquartile range of the reviewed studies of 54-73 g CO_2-eq/kWh is presented (median 63 g CO_2-eq/kWh). O'Donoughue et al. (2014) review and harmonize LCA greenhouse gas emission results for conventional gas based electricity generation. Heath et al. (2014) harmonize shale gas life cycle emissions. Methane leakage is discussed and ranges from 0.2 % to 6 % of natural gas production in the reviewed studies. Corsten et al. (2013) review the LCAs of both coal and natural gas based electricity generation in combination with CCS. They conclude that the upstream emissions of natural gas lead to large impacts on the overall GHG emissions, to the extent that electricity generated by a natural gas combined cycle power plant with CCS appears to have associated GHG emissions of the same order of magnitude as pulverized coal generated electricity with CCS.

Several recent studies focus on fugitive methane emissions from conventional and unconventional fossil fuel production. Weber and Clavin (2012) perform a Monte Carlo analysis based on six previous studies for natural gas from conventional and unconventional sources. Burnham et al. (2012) compare results for emissions related to coal and natural gas, shale gas and petroleum. Both studies conclude that upstream methane leakage and venting can reduce significantly the life cycle benefit from gas compared to coal, and that gas related emissions from conventional or shale production are statistically indistinguishable in a life cycle perspective. Laurenzi and Jersey (2013) study GHG emissions and water consumption of Marcellus shale gas production, but indicate that for certain GHG emissions EPA emission factors are used. They find that the estimated ultimate recovery of shale wells is one of the major determinants in the life cycle GHG emissions of shale gas electricity generation.

Though there are differences between the LCA studies of power plants with and without CCS in the literature, relatively little attention has been paid to fugitive emissions. These are mainly included by application of an emission factor and sometimes discussed as a subject of sensitivity analysis. In addition, most studies have a limited regional scope, evaluating power plants in Europe or the United States, with the shale gas literature focusing almost solely on the United States. This leads to the questions to what extent data are available with respect to fugitive methane emissions for both coal and natural gas, how they vary regionally, and consequentially what that implies for the environmental performance of fossil fuel power generation with and without CCS.

The aim of this paper is to make an inventory of the ranges of fugitive methane emissions available in the literature and assess the consequences these emissions have on the life cycle GHG impacts of fossil fuel power generation. We focus on fugitive methane emissions of coal mining, conventional natural gas production and shale gas production. The hybridized multiregional life cycle assessment model THEMIS (Technology Hybridized Environmental-economic Model with Integrated Scenarios) is used (Hertwich et al., 2014), in combination with a set of life cycle inventories for state-of-the-art fossil fuel power plants, both with and without CCS facilities. We allow for regional variation of fugitive emissions in order to increase understanding of the environmental consequences of implementation of fossil fuel power generation in different regions.

2. METHODS

In this section we discuss the approach followed to assemble the fugitive emission datasets with special focus on the data reported in UNFCCC. We continue with a description of the HLCA model employed. The system description for the HLCA and life cycle inventories used are described separately in section 3 of this paper.

2.1 Dataset assembly fugitive emissions

Three datasets were compiled containing a total of 227 entries for coal fugitive emissions, 34 entries for conventional gas fugitive emissions and 19 entries for shale gas emissions, based on peer reviewed published literature as well as data reported as part of the United Nations Framework Convention on Climate Change (UNFCCC). The UNFCCC was established in 1992 at the United Nations Conference on Environment and Development in Rio de Janeiro. The treaty has the objective to achieve *'...stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system...'* (United Nations, 1992). Annex I countries that have ratified the convention, report national greenhouse gas inventories yearly in the form of a national inventory report (NIR) and the common reporting format (CRF). The NIRs contain detailed information for each country and the CRF is an electronically submitted series of standardized data tables for all greenhouse gas emissions per sector. According to the guidelines governing the reporting on annual inventories, the estimates of emissions should be comparable among parties. In order to do so, countries have to follow the IPCC guidelines (IPCC, 2006) to estimate and report on anthropogenic emissions, but are free to use the different methods included in those guidelines (UNFCCC, 2004). Though data should be comparable between countries, there are different levels of uncertainty related to the UNFCCC data, which are related to the different calculation approaches accepted in the IPCC guidelines. Countries can report data using a tier 1 approach. In this approach, associated with the highest level of uncertainty, total emissions are calculated using a global average range of emissions factors and country-specific activity data. In the tier 2 approach, emissions are calculated using country or basin specific emissions factors. In the tier 3 approach, associated with the lowest level of uncertainty, direct measurements on a mine-specific basis are used (IPCC, 2006). Though not reported in the tables of the CRF, the NIRs contain information about the approaches used by Annex I countries (commonly mixes between tiers 1, 2, and 3) in reporting emissions data.

In this paper, we used the data provided by the Annex I countries in Tables 1.B.1 and 1.B.2 of the CRF, that describe the fugitive emissions from solid fuels (1.B.1) and oil, natural gas and other sources (1.B.2) (UNFCCC, 2012). We selected for each country the average, minimum and maximum emissions of the time series from the starting year of reporting (usually 1990, though there are variations between countries) until 2010. These country level data were subsequently aggregated to generate a list of regional estimates of methane emissions related to coal production and conventional natural gas production. The regions correspond to the regional division of our HLCA model, which is described in section 2.2.

In this study, values larger than 1.5 times the global interquartile range above the (global) 3rd quartile were considered outliers and were removed from the database. This was the case for natural gas data reported by Ukraine and Greece (respectively 1025 and 837 g CH_4/m^3 natural gas) and some of the coal data for Russia and France. Such high numbers may be due to the application of too uncertain emissions factors in the tier 1 method and possibly aggregation of fugitive emissions related to the natural gas transportation infrastructure in the UNFCCC common reporting format.

Because the United States is the only country with significant past shale gas production and because there is no distinction in the UNFCCC natural gas data regarding the source (conventional or shale) of methane emissions, we assumed that UNFCCC natural gas emissions data are only relevant for the conventional natural gas system.

In addition to official emissions reports scientific literature sources were consulted. Coal mining, conventional natural gas extraction, and shale gas extraction are described by (Burnham et al., 2012). Shale gas is included in (Howarth et al., 2011; NETL, 2014 ; Weber and Clavin, 2012). A set of emissions factors for coal mines was found for the regions China, OECD Pacific and Economies in Transition (mainly Russia) (Bibler et al., 1998; EPA, 2006; NETL, 2010f; Saghafi, 2012; Su et al., 2011; Sørstrøm, 2001), thus generating at least one dataset for five different regions in the HLCA model. Table 1 shows the regional coverage of the three datasets compiled based on the references consulted. The total number of data points per region and source is presented in Table ST1 of the supporting information.

Table 1
Regional coverage of datasets investigated

Reference	Coal	Conventional gas	Shale gas	Regions[a]
UNFCCC, 2012	X	X		RER;US;PAC;EIT
Burnham et al., 2012	X	X	X	US
Weber and Clavin, 2012		X	X	US
Howarth et al., 2011		X	X	US
Sørstrøm, 2001	X			RER;US;EIT
Su et al., 2011	X			CN
Bibler et al., 1998	X			CN
EPA, 2006	X			RER;US; EIT
Saghafi, 2012	X			PAC
NETL, 2010f	X			US
NETL, 2014		X	X	US

[a] Region abbreviations are: CN = China, RER = OECD Europe, US = OECD North America, PAC = OECD Pacific, EIT = Economies in Transition

2.2 HLCA model

A multi-regional integrated hybrid life cycle assessment (HLCA) model was employed to model the potential environmental impacts (Hertwich et al., 2014). We modeled a traditional process based Life Cycle Assessment and complemented this with economic data where these were available. The model was set-up as a tiered hybrid model, in which it is possible to select for each unit process background data from both a physical inventory, ecoinvent 2.2 (Dones et al., 2007), and an environmentally extended Input-Output database EXIOBASE (Tukker et al., 2013). In the THEMIS model, EXIOBASE is aggregated to nine regions from its original regional classification, but incorporates a disaggregated electricity sector (Hertwich et al., 2014). Potential environmental impacts were calculated on a per-kWh electricity produced functional unit basis. For the LCA we took a cradle-to-gate approach.

As methane is an important greenhouse gas, we evaluated GHG emissions using Global Warming Potentials (GWPs) over a 100-year time horizon. For each of the emission factors found in the literature the appropriate stressors were adapted and the LCA model was run, which generated a range of model outcomes for the climate change impact associated with the fossil electricity generation. The ecoinvent database contains nine unique processes that cover natural gas extraction and ten processes for the extraction of hard coal. A shale gas extraction process did not exist in the database, and therefore an inventory was built based on data from the Argonne National Laboratory (Clark et al., 2011). All modeling was performed in Matlab in combination with an Excel interface for data input.

The life cycle inventory data are based on state-of-the-art power plants described by several reports of the National Energy Technology Laboratory in the US. These studies present detailed cost economic modeling of power plants and life cycle inventories (NETL, 2010a, b, c, d, e), thus providing a suitable starting point for hybrid life cycle assessment. Where data were not sufficient, or too specific for a generic power plant, peer reviewed literature was consulted to provide input data (Koornneef et al., 2008; Singh et al., 2011a; Veltman et al., 2010).

3. LIFE CYCLE INVENTORY

Four different types of electricity production technologies were modeled. The investigated technologies are:

i) subcritical pulverized coal fired power (Sub-PC)

ii) supercritical pulverized coal fired power (SCPC)

iii) integrated gasification combined cycle (IGCC)

iv) natural gas combined cycle (NGCC)

Out of these technologies, three are connected to a post-combustion CO_2 capture process (using amine as solvent) and one is connected to a pre-combustion CO_2 capture process (using a solvent consisting of dimethyl ethers and polyethylene glycol). Key characteristics of these technologies are described in Table 2. We evaluate the power plants on a cradle-to-gate perspective. Electricity transport and distribution to the end users is outside the scope of the study. Each life cycle inventory is set up according to the following structure: fossil fuel extraction, fossil fuel transport, power plant operation and a separate foreground process for power plant infrastructure. For the inventories in which carbon capture and storage is included, the following foreground processes are added: CO_2 capture and compression, CO_2 transport by pipeline, and the CO_2 injection well. The key foreground processes are shortly discussed in the following sections. Information regarding specific emissions and the efficiencies of emissions reduction measures implemented with each power plant is given in the table ST2 in the Supporting Information.

Table 2
Key power plant characteristics (NETL, 2010a)

	Unit	Sub-PC	SCPC	IGCC	NGCC
Net power output without CCS	MW	550	550	629	555
Net power output with CCS	MW	550 [a]	550 [a]	497	474
Capacity factor	%	85	85	80	85
Net plant efficiency without CCS	%	38.2	40.7	43.6	55.6
Net plant efficiency with CCS	%	27.2	29.4	32.3	47.4
Fuel requirements	kg/kWh	0.361	0.338	0.315	0.187 (m^3/kWh)
Fuel requirements with CCS	kg/kWh	0.507	0.467	0.425	0.219 (m^3/kWh)
CO_2 emissions from power plant	g/kWh	856	802	723	365
CO_2 emissions from power plant with CCS	g/kWh	120	111	109	42.6
MEA consumption	kg/tonne CO_2	2.15	2.15	0.09 (dimethyl ether)	2.15
CO_2 capture efficiency	%	90	90	90	90
Lifetime	years	30	30	30	30

[a] The nominal net output for the Sub-PC and SCPC cases was maintained at 550 MW for the cases with CCS. This is done by increasing the boiler and turbine/generator sizes to account for a larger auxiliary load due to the carbon capture process. For the IGCC and NGCC cases, the plant size was kept constant, leading to a lower net power output.

The following sections describe our base inventory for the four investigated power plant technologies. As the purpose of this paper is to show how varying emissions upstream can influence the LCA results related to power generation we do not change the efficiency of the power plants between regions. However, as our base inventory (presented in Tables ST5-ST16) is based on fuels with very specific energy and carbon density, we assume a regional specific lower heating value (LHV) for the fuel used in order to adapt the fuel requirement and direct emissions of power plant operation for each region. The scaling factors we developed to adapt these flows in the base inventory are presented in Tables ST3 and ST4 of the Supporting Information. The regional specific LHV is used to calculate the fossil fuel input for the power plant in each region. Direct emissions of power plant operation are scaled with both regional specific LHVs and carbon content. To that extent, we assembled a set of coal carbon content (CC) and LHV pairs (in the range of 18-31 MJ/kg coal), that were used in previous LCAs and express CC as function of LHV (Whitaker et al., 2012). In the specified LHV range we assumed that this function behaves linearly for all practical purposes. The scaling factor for direct power plant emissions was calculated based on the relative change of the ratio between calculated CC and regionally specified LHV. Since the variation in the LHV of natural gas used in the model is relatively low, we have chosen to use the same scaling factor for both natural gas inputs and emissions.

3.1 Fossil fuel extraction

Three types of extraction processes are modeled in this paper: coal mining, conventional natural gas extraction, and shale gas extraction. For coal and conventional natural gas the ecoinvent processes *hard coal, at mine* and *natural gas, at production* are used, with the exception of making the fugitive methane emissions in these processes a model variable. Please note that, for coal, we do not explicitly distinguish between underground and surface coal mining processes, but use the underground/surface mine ratio in the ecoinvent database.

A shale gas extraction process was modeled based on data published by the Argonne National Laboratory (Clark et al., 2011). A well production over a lifetime of 30 years of 98 million cubic meters was assumed, though it should be noted that much shorter lifetimes have been reported (O'Sullivan and Paltsev, 2012). Material requirements for the drilling and construction of the well pads are taken as the non-weighted average of four shale gas plays in the United States (namely, Barnett, Marcellus, Fayetteville, and Haynesville). The fracking fluid is a mixture of water and sand with a range of organic and inorganic chemicals such as methanol, hydrogen chloride, formaldehyde, sodium hydroxide and ethylene glycol. The inventory for the fracking fluid is given in table ST5 of the Supporting Information.

Electricity and diesel fuel consumption for well operation are taken as an average of four wells described by Clark et al. (2011). Within our model, the emissions associated with well completion and well workovers are not explicitly stated, but are part of the well operation process, as many sources report well completion in percentage of natural gas during production. The methane emissions for well completion and workovers are reported to be 417 tonnes of methane per well over its life cycle (Clark et al., 2011). Table ST6 in the supporting information shows the required material inputs and methane emissions associated with the construction of a shale gas well as modeled in this study and Table ST7 shows the inventory for shale well operation.

3.2 Fossil fuel transport

In this study, the coal fired power plants are assumed to use the same coal transport unit process. Coal is transported by rail over a distance of 330 km from the excavation site to the power plant (NETL, 2010e). The material requirements for the trains are included in the inventory, as well as diesel required for transport. The rails themselves are assumed to be constructed and available and are not included in the inventory. During coal extraction and transport it is assumed that no coal is lost. The coal transport inventory is presented in Table ST8 of the supporting information.

Gas is assumed to be transported 1000 km by pipeline, connecting an offshore natural gas extraction site and the power plant location (ecoinvent process *transport, natural gas, pipeline, long-distance*). Although the shale gas wells are land based and it would be expected that the transport distance is shorter, it was chosen to keep the pipeline length constant, in order to make inventories more comparable. Methane leakage during transport is assumed at 0.026 % of transported natural gas per 1000 km based on ecoinvent (Faist Emmenegger et al., 2007).

For Russia, the ecoinvent leakage rate is considerably higher at 0.23 % per 1000 km (1.4 % for a transport distance of 6000 km) (Faist Emmenegger et al., 2007). Leakage rates for transmission and distribution of 0.67 % (0.29 % - 1.05 %) to 1.5 % (0.8 % - 2.2 %) are reported for the US, but a specific transport distance is not reported (Burnham et al., 2012; Weber and Clavin, 2012). To study the increase in contribution of methane to the life cycle impacts, the natural gas transport process was updated with the values for the EIT (0.23 %) and the US (0.67 %). We report the influence of different natural gas pipeline fugitive emissions rates in section 4.3.

3.3 Pulverized coal fired power plants

The baseline inventory includes both sub- and supercritical coal fired power technology (see tables ST9 and ST10). Both coal fired power plants are based on designs from the National Energy Technology Laboratory (NETL, 2010a). Key plant characteristics are given in Table 2. Main inputs are taken from the ecoinvent background. The largest flows are hard coal fuel, limestone for the flue gas desulphurization unit, ammonia for the selective catalytic reduction of NOx emissions and water for cooling duties. In addition, for the CCS processes, monoethanolamine (MEA), caustic soda, and activated carbon are also used. The treatment of waste generated by the power plants, is modeled following ecoinvent. Main emissions for the power plants without CCS are carbon dioxide, water vapor, particulate matter, sulfur dioxide and nitrogen oxides (NETL, 2010b, e). The flue gas desulphurization process in the coal fired power plants yields gypsum as an economic byproduct. In this paper, we take a conservative approach and no impacts are allocated to gypsum production. In power plants with CCS, ammonia and MEA emissions are also included. The CO_2 captured is transported in dense phase and is compressed on-site to 153 bar before transport. The electricity for compression is generated by the power plant and it is included in the energy penalty due to CO_2 capture. It is further assumed that no extra cleaning equipment is required and that dehydration during compression reduces the water content to at least 500 ppmv, making it suitable for transport. Power plant infrastructure, as well as chemicals that constitute minor inputs, are modeled using flows from the economic EXIOBASE background (see tables ST12 and ST13).

3.4 Integrated gasification combined cycle

The integrated gasification combined cycle power plant is modeled based on the designs of NETL (NETL, 2010a). The key plant characteristics are given in Table 2. Main inputs are taken from the ecoinvent background (see table ST8). Before combustion, coal is gasified producing a mixture of hydrogen and carbon monoxide. As noted before, the coal transport process is assumed to be the same as the transport process for the sub- and supercritical power plants. Due to its higher efficiency, the fuel requirements for the IGCC are somewhat lower than those for the pulverized coal power plants. Besides coal, the main inputs to plant operation are process water for cooling duties, catalyst for the COS hydrolysis unit (in the case of the IGCC without CCS) and activated carbon for the removal of mercury. In the case of IGCC with CCS, the water gas shift reactor also hydrolyses carbonyl sulphide (COS) into H_2S, hence no separate COS hydrolysis reactor is needed. A mixture of dimethyl ethers and polyethylene glycol is used as a physical solvent for both the IGCC plant with and without CCS and is used for mainly sulfur removal (single stage) or for both sulfur and CO_2 removal (dual stage). Though sulfur is a byproduct of the IGCC power plant, the same approach as with the gypsum production in the supercritical power plant is followed, thus impacts are not allocated with respect to sulfur. The solvent has a low vapor pressure, and spent solvent is therefore assumed to end up in the solid waste output of the power plant (Singh et al., 2011b). Main emissions for the IGCC power plant are carbon dioxide, water vapor, particulate matter, sulfur dioxide and nitrogen oxides. The CO_2 captured is compressed to 153 bar before transport. Power plant and CCS infrastructure, as well as chemicals that constitute minor inputs, are modeled using flows from the economic EXIOBASE background (see tables ST15 and ST16).

3.5 Natural gas combined cycle

The natural gas plant is modeled as a combined cycle plant (NETL, 2010a). Besides natural gas, the main plant inputs are ammonia for the selective catalytic reduction (SCR) of NO_x, process water for cooling duties and chemicals such as the catalyst of the SCR unit. Inputs to the CO_2 capture process are activated carbon and MEA. Main emissions for the NGCC power plants are carbon dioxide, water vapor, ammonia, and nitrogen oxides (see table ST9). The CO_2 captured is compressed to 153 bar before transport. Similar to the other inventories, infrastructure is modeled using the EXIOBASE economic background (see tables ST15 and ST16).

3.6 CO_2 transport and storage

Captured carbon dioxide is assumed to be transported to an underground aquifer by pipeline. CO_2 is transported in dense phase over a transport distance of 150 km. As the inlet pressure was 153 bars, the pressure drop over the 150 km pipeline is small enough to prevent two-phase formation and therefore intermediate booster stations are not required. Following the approach by Singh et al. (Singh et al., 2011a), pipeline inventory data are modeled after a high capacity offshore natural gas pipeline from ecoinvent (see table ST13). Carbon dioxide leakage from the pipeline is assumed to be 0.01% of transported CO_2 (see table ST14, (Koornneef et al., 2008)).

Captured CO_2 is injected in an aquifer at a depth of 1200 m. It is assumed that no booster compression is required at the wellhead, though this will be determined by site specific pressure conditions in the bottom well. The CO_2 injection rate per well is 9.4 kt CO_2 per day and is modeled as an offshore drilling well from ecoinvent (Singh et al., 2011a). In this study it is assumed that the reservoir is large enough to store the CO_2 over the lifetime of the power plant and that CO_2 is stored permanently (that is, there is no leakage from the reservoir).

4. RESULTS

4.1 Dataset analysis

Figure 1**Error! Reference source not found.** shows the fugitive methane emissions within the data assembled. As can be seen for both coal and natural gas, fugitive emissions vary by orders of magnitude. The figure shows the outlier-adjusted minimum and maximum values for the different regions in the dataset (indicated by the lines), and the first and third quartile of the data (indicated by the box). In addition to the different regions, the global range is also presented. The regions China and Economies in Transition show clearly higher emissions associated with coal than the United States and Europe. There is a large spread in the European data as the result of some very low emissions (0.01 g CH_4/kg coal) reported in the UNFCCC data. Methane emissions from gas production in North America are larger than those in Europe and the Economies in Transition. This divergence raises the question to what extent higher reported emissions in the US are due to difference in practice and specific site conditions and to what degree it could be the result of more attention to the issue, as indicated by the relatively high attention for (US) fugitive emissions in scientific literature. The results also indicate that fugitive emissions associated with shale gas are on average higher than for conventional natural gas production. This can be due to the large uncertainty involved in the emissions associated with well completion and workover emissions. For example, these emissions are reported to be in the range of 0.006-2.75% of natural gas production (Burnham et al., 2012). Dataset analysis did not reveal an obvious distribution of the emissions factors in the UNFCCC data, even though a lognormal (Dones et al., 2007) and triangular distribution (Weber and Clavin, 2012) have been assumed previously for the purpose of Monte Carlo simulations.

It is important to note here that the large ranges of fugitive emissions shown are caused by both natural variation and uncertainty in the data. For example, differences in coal grade and rank between mines have an influence on the methane emissions included in the coal bed (Moore, 2012). Furthermore, surface mines are more likely to have been vented by natural processes and can therefore be expected to have lower associated fugitive emissions than underground mines. In addition, natural gas is captured from coal seams (coal bed methane) thereby reducing the potential fugitive emissions of to-be extracted coal (NETL, 2014). The range of emissions related to gas infrastructure is most likely a result of the inherent uncertainty involved in the quantification of emissions using the tier 1 and 2 methods.

<FIGURE 01>

4.2 Life Cycle Impact Assessment

In this section, the results of the life cycle impact assessment are presented. Figure 2 presents a boxplot of impact assessment results for the climate change impact category in g CO_2-eq per kWh for all technologies investigated and based on a global warming potential evaluated at a 100 year time horizon (Solomon and Miller, 2007). It is shown that the results vary considerably, with China and the Economies in Transition showing the highest impacts, as can be expected from the fugitive emissions range presented in Figure 1. The full range of results for coal fired technology without CCS lies between 747 and 1303 g CO_2-eq./kWh of electricity produced. Not surprisingly, for the cases without CCS, natural gas power plant emissions are lower than coal fired power emissions, and lie between 367 and 533 kg CO_2-eq./kWh. For the coal fired power plants, the average contribution of methane emissions varies considerably between 4% in the OECD Pacific region and 15% in China. For the natural gas fired power plants this range is wider with the average contribution of methane ranging from 3 % in Europe up to 16 % for shale gas in the US.

Though there are large differences in the contribution of methane to GWP between regions, we see no significant difference in relative methane contribution for the three different coal technologies without CCS.It is important to note here that the difference between regions has a three-fold origin. The first one is the variation in the fugitive emissions rates between regions according to the data ranges shown in Figure 1. The second is due to the introduction of the regional specific LHVs for coal and natural gas. In regions with relatively low LHV (e.g. China) the higher fuel requirements translate into a higher contribution of methane to the GWP. Thirdly, the regionalized background contained in THEMIS introduces some variation in regional GWPs. For example, the electricity mix used in the production of the diesel fuel used in the transport of coal varies between regions. In the case of fossil fuel power plants the contribution of the regionalized background is small, as most of the emissions are associated with the foreground processes.

The inclusion of CCS decreases the environmental impacts of power plants considerably, with GHG results ranging from 128 to 747 g CO_2-eq./kWh for coal fired power plants. Results for natural gas plants lie between 75 and 250 g CO_2-eq./kWh. The average contribution of fugitive methane emissions after installing CCS technology ranges from 23 % to 50 % for coal and 19 % to 56 % for natural gas. Contrary to the cases without CCS, we can observe differences in the average contribution of methane emissions between technologies (for equal regions) since the direct emissions of the power plant become less dominant.

In the interest of comparability we have not included intra-regional changes in both LHV and efficiency of the power plant. An increase in power plant efficiency will shift the entire range of GWPs proportional to the decrease in fuel requirements. An increase in LHV would also result in lower fuel requirements, but most likely would affect direct power plant emissions much less due to the associated increase in carbon content. The opposite is valid for decreases in both efficiency and LHV. The above presented numbers show the importance of mitigation of methane emissions in the fossil fuel extraction process, as these emissions contribute largely to the emissions associated with fossil fuel power generation, especially for fuels with a relatively low LHV. It should be noted here that results for gas fired power plants and coal fired power plants partially overlap when carbon capture technology is installed, a conclusion also reached by for instance Corsten et al. (2013).

<FIGURE 02>

4.3 The influence of natural gas transport emissions

So far, we have explored only the fugitive emissions associated with the extraction of fossil fuels. However, emissions also occur in the transport of natural gas. As described before, the natural gas transport process was updated with new values for EIT (0.23%) and the US (0.67%). The results are presented in Table 3. We see a small increase for the EIT, even though emissions associated with transport are increased by an order of magnitude. Not surprisingly, the change is more apparent for North America, due to the high rate of emissions assumed to be associated with transport. However, it is not clear whether the 0.67% natural gas loss would be consistent with the pipeline length of 1000 km that is used in our model. Rather than estimating the contribution of emissions associated with natural gas transport, the purpose here is to show that emissions associated with transport have to become relatively high (as indicated by the US emissions rate) in order to become significant compared to fugitive emissions during extraction.

Table 3
The contribution of methane to the life cycle GHG emissions of power production when including region-specific transport emissions[a]

	EIT	US
NGCC	9% (8%)	16% (12%)
NGCC + CCS	34% (29%)	54% (45%)
NGCC shale	n.a.	20% (16%)
NGCC + CCS shale	n.a.	61% (56%)

[a] Values in brackets indicate the methane contribution with generic transport emissions previously used.

5. DISCUSSION

The direct comparison of LCA results between different studies is always hampered by differences in system boundaries, plant type investigated, and background database used. For example, Burnham et al. (2012) use an NGCC power plant efficiency of 47% and a supercritical coal power plant efficiency of 41.5% (compared to respectively 55.6 % and 40.7% used in this paper). Modelling is performed with the GREET model, and not with ecoinvent. In this section we therefore compare qualitative results rather than quantitative results.

Burnham et al. (2012) have concluded that total upstream emissions can reduce the life-cycle benefit for natural gas compared to coal, which the current study also indicates. There is no agreement in the literature on the comparison on the magnitude of shale gas emissions compared to conventional natural gas emissions and appears to be strongly tied to the shale well lifetime and associated ultimate recovery (Laurenzi and Jersey, 2013; O'Sullivan and Paltsev, 2012). In our modeling we see on average a larger impact for US shale than for US conventional gas, but we would like to point out that the ranges overlap to a considerable extent. Both Weber and Clavin (2012) and Laurenzi and Jersey (2013) conclude that the relative difference in GWP between conventional and shale gas production is smaller than the uncertainty in either estimate. As gas is increasingly extracted from unconventional sources special attention to methane emissions could provide a significant mitigation opportunity.

While fossil fuel power plants with high GHG emissions are reported in the literature, these emissions are generally caused by a low efficiency of the power plants (Whitaker et al., 2012). Our results show that even modern power plants can have high life cycle GHG emissions due to fuel chain methane releases. They also show that fuel energy density and associated carbon content are an important parameter in determining fuel requirement, and hence the contribution of fugitive emissions, and direct emissions of power plant operation. It should be noted that the non-methane upstream contribution is in the order of 1-4 %, mainly diesel combustion during operation of machinery and transport of coal, or carbon dioxide emissions associated with combustive processes during natural gas extraction and transport.

All impact results in this paper are reported using global warming potentials with a 100-year time horizon and a characterization factor for methane of 25 kg CO_2-eq/kg CH_4. In the latest round of IPCC reports, the characterization factor was updated to 34 kg CO_2-eq/kg CH_4. For GWPs evaluated over a 20-year time horizon the methane characterization factor is considerably larger at 86 CO_2-eq/kg CH_4 (Myhre et al., 2013). The methane characterization factors show that the contribution of methane to radiative forcing is significant, especially in the short term. Several authors have tried to capture this by developing alternative models such as Technology Warming Potential (Alvarez et al., 2012) and Time Adjusted Warming Potential (Kendall, 2012).

6. CONCLUSION

The aim of this paper was to provide a better understanding of methane emissions associated with the extraction of fossil fuels and assess their effect on the life cycle impacts of fossil fuel power generation. A set of life cycle inventories was assembled and combined with a dataset of fugitive methane emissions in a multiregional hybrid LCA model. The results of the dataset analysis reveals that fugitive emissions can vary by orders of magnitude, both inter- and intraregional. Our impact assessment results indicate that fuel chain methane emissions can constitute a substantial portion of the total emissions from fossil fuel power, and both their absolute magnitude and relative importance will increase with the deployment of CCS. In the most extreme cases, emissions from the fuel chain could be of equal importance to emissions from a power plant with CCS.

We see that methane emissions from fossil fuel production vary more widely than commonly acknowledged in the LCA literature, and that there are distinct regional disparities. By including the regionalization in our model we provide a more detailed picture of the contribution of fugitive methane emissions to the total life cycle impact. Coal methane emissions are more relevant for power plants in the regions China and Economies in Transition, with contributions over 40% for plants with CCS technology included, than for similar plants in Europe and North America. This is a result from higher fugitive emissions during extraction and the increased fuel requirements related to the use of fuel with a lower energy density. However, in the case of natural gas extraction, the contribution of fugitive emissions is significant for the North American region, with an average contribution that can exceed 50 % for the plants with CCS technology. European conventional natural gas production appears to have the lowest amount of fugitive emissions associated. The inclusion of higher emissions associated with natural gas pipeline transport becomes only significant when gas leakage rates increase by at least an order of magnitude compared to leakage from the European grid, which was used as the default ecoinvent process.

The regional disparities may not reflect differences in geological factors, technologies, and practices employed. Most emissions estimates in both the UNFCCC data and literature are based on engineering calculations and not measurements, with only one paper utilizing actual measured shale gas production data. More measurements and an in-depth review of the engineering calculations are required to illuminate whether reported differences reflect actual variation in emissions or our uncertainty about them. A more clear approach on how many of the data points are generated using tier 1, 2, 3 or mixed methods. In addition, most literature seems to focus on processes in the United States, but as this study shows, there is a need for detailed empirically determined emissions data in both North America and other regions, as the uncertainties related to the data reported under the UNFCCC common reporting format are not sufficiently quantified.

Given the large impact of methane emissions on LCA results we recommend practitioners to be aware of the sensitivity and to always perform a sensitivity analysis addressing uncertainty related to the upstream processes. Depending on timeframe and scope, there are examples of detailed inventories (NETL, 2014) in which fugitive emissions are addressed on a component specific level that could be adapted to specific conditions.

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FIGURE CAPTIONS

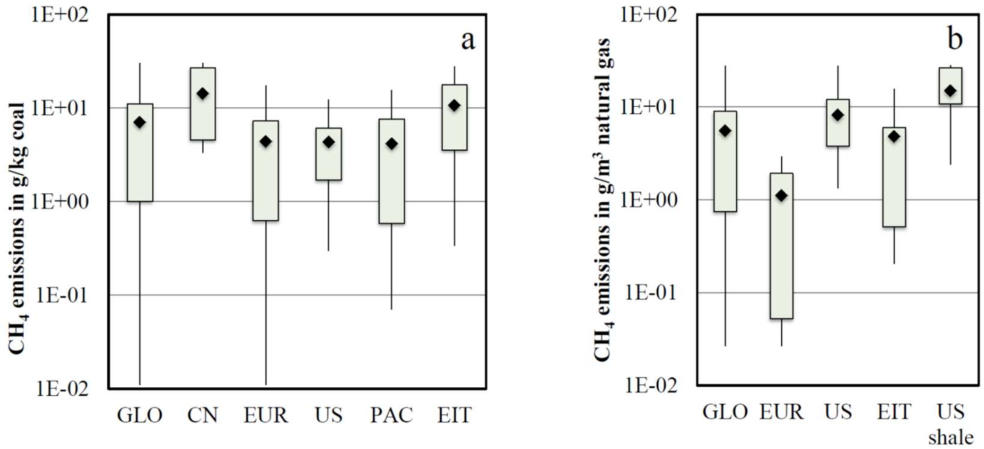

Figure 1(a-b): Reported fugitive methane emissions for the extraction of coal (a) and extraction of natural gas (b). GLO = global, CN = China, EUR = OECD Europe, US = OECD North America, PAC = OECD Pacific, EIT = Economies in Transition. N.B. Emissions associated with natural gas production from conventional and shale source is presented separately in columns US and US shale of panel b.

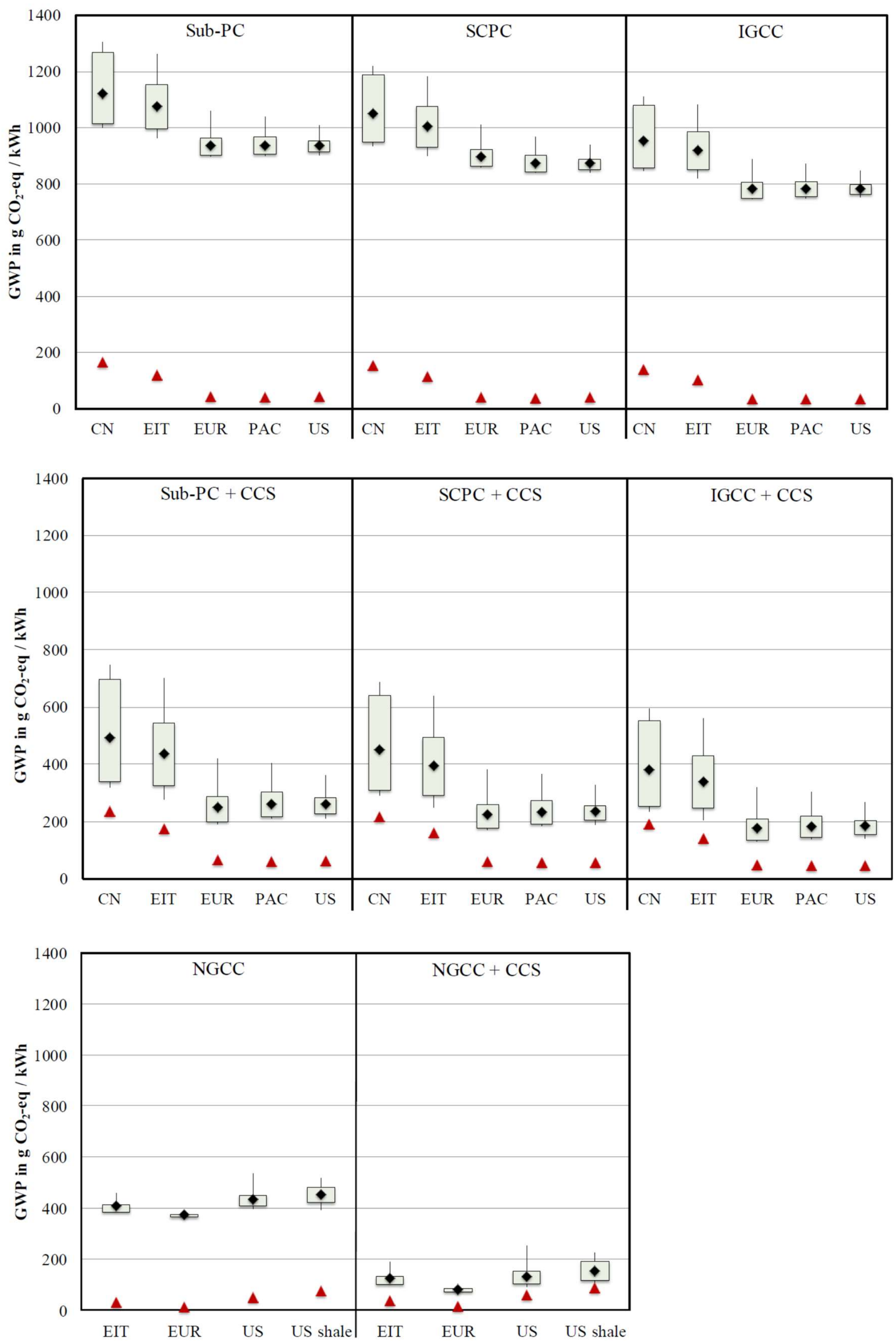

Figure 2: Calculated Global Warming Potential per kWh energy produced in sub-, supercritical, integrated gasification coal fired power plants, and natural gas fired

power plants for the year 2010. Results are based on different fugitive emissions during fossil fuel extraction. Sub-PC = subcritical pulverized coal, SCPC = supercritical pulverized coal, IGCC = integrated gasification combined cycle, NGCC = natural gas combined cycle. The plotted triangles indicate the average contribution of methane emissions to the impact assessment. The plotted diamonds indicate the average GWP.