A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies

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Abstract: This manuscript reviews and compares the results of recent greenhouse gas (GHG) emission life-cycle analyses. Specific attention is paid to fossil energy technologies, nuclear and renewable energy technologies (RETs), as well as carbon capture and storage (CCS) and energy storage systems. Analysing up-and downstream processes and their associated GHG emissions, which arise upstream and downstream of the power plant (i.e., electricity generation stage), is important; otherwise, the GHG emissions resulting from electricity generation of the various fuel options are underestimated. For fossil fuel technology options upstream GHG emission rates can be up to 25% of the direct emissions from the power plant, whereas for most RETs and nuclear power upstream and downstream GHG emissions can account for way over 90% of cumulative emissions. In economies where carbon is being priced or GHG emissions constrained, this may provide an advantage to technologies with trans-boundary upstream emissions over technologies without significant life-cycle emissions arising outside the legislative boundaries of GHG mitigation policies. It is therefore desirable for GHG emissions under national, regional and international mitigation policies to be accounted for over its entire life-cycle. The results presented here indicate that the most significant GHG avoidance (in absolute terms) can be made from technology substitution. The introduction of advanced fossil fuel technologies can also lead to improvements in life-cycle GHG emissions. Overall, hydro, nuclear and wind energy technologies can produce electricity with the least life-cycle global warming impact.

Keywords: *greenhouse gas emission, life-cycle analysis / assessment, energy technology, electricity, fossil fuels, renewable energy technologies, global warming, climate policy, nuclear energy chain*

1 Introduction

All energy systems emit greenhouse gases (GHG)[1] and contribute to anthropogenic climate change. It is now widely recognised that GHG emissions resulting from the use of a particular energy technology need to be quantified over all stages of the technology and its fuel life-cycle. While accurate calculation of GHG emissions per kilowatt-hour (kWh) is often difficult, sound knowledge of life-cycle GHG emissions can be an important indicator for mitigation strategies in the power sector.

To date a great variety of GHG life cycle assessments (LCA) of power plants has been conducted. For example, Van de Vate reports on the status of life-cycle GHG emissions from hydropower [1] and energy sources [2] based on International Atomic Energy Agency (IAEA) expert meetings, Frankl et

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[1] Each GHG has active radiative (or heat-trapping) properties. To compare GHGs emissions from different sources, they are indexed according to their global warming potential. Global warming potential (GWP) is the ability of a GHG to trap heat in the atmosphere relative to an equal amount of carbon dioxide. According to the Intergovernmental Panel on Climate Change (IPCC), over a 100-year time span carbon dioxide (CO_2) assumes the value of 1. The two other GHGs of importance in this analysis are methane (CH_4) and nitrous oxide (N_2O) which, according to a re-evaluation of the IPCC in 2001, take a value of 23 and 296 respectively. Prior to 2001 the IPCC has assumed a 100 year GWP of 21 and 310 for CH_4 and N_2O respectively, which may explain for some minor differences in the results of studies preceding 2001.

al [3] on Photovoltaic (PV), Kreith et al [4] on fossil and solar power plants, Proops et al al [5] on various types of electricity generation, Yasukawa et al [6] on nuclear power and the nuclear fuel cycle, and Uchiyama [7] on several electricity generation and supply systems. Dones, Gantner and Hirschberg [8] evaluated GHG emissions from electricity and heat supply systems. There are many more. While on one hand, all of these *older* studies have helped shed light on the cumulative GHG emissions of power generation, on the other hand, their sometimes significantly different results – especially at individual upstream or downstream stages of the life-cycle – have created confusion amongst policy makers and scholars alike as to their accuracy or application.

This paper presents and analyses the life-cycle GHG emission of electricity generation chains (i.e. single and country / region averages) based on *recently* published assessments, and identifies the underlying mechanisms, that frequently lead to conflicting life-cycle emission results in these studies, such as methodological approach, geography of fuel supply and mixes, heating values and carbon emission factors, system boundary assumptions etc. Appreciating and understanding the discrepancies in these results is crucial for GHG LCA to play a role in guiding policy. In addition, the implications of life-cycle GHG emissions for climate policy are discussed since most policies address the release of GHG emissions by focusing on large-scale stationary point-sources, thereby potentially failing to embrace significant up- and downstream emissions outside those well-defined boundaries.

The second section in this analysis briefly discusses some aspects of the data and studies that have been used. The third section analyses *direct* emissions from fossil fuel power plants in different regions of the world to illustrate, that significant variations in GHG emission per unit of electricity exist for same fuel technologies due to technology specification, thermal efficiency and heating value. The fourth section discusses commonly used methodologies for LCA, as well as the benefits and limitations of LCA in general and specific to the methodology used. The fifth section discusses the results of the GHG LCA of several studies for conventional fossil fuel technologies, nuclear power, wind, PV, hydro and biomass. Further, the life-cycle GHG emissions for storage technologies and carbon capture and storage (CCS) are analysed.

The results presented here are *generic*, since the comparison of results presents an overview of emissions that can be usually expected. However, variations exist according to site-specific conditions (e.g. technology, carbon content of fuel, climatic conditions etc.). This comparison can be practical for policymakers, since policy decisions are often required before detailed site-specific information becomes available [9].

2 Use of data & studies

In this work, life-cycle emissions are presented for current power generation technologies, although some estimation of GHG emissions for advanced and future technologies is provided. The size of the plants is not considered unless specified and typical conditions are provided for Europe, North America, and Japan and in one case, China. Only original studies have been used to ensure that all data can be traced back to the original references. The LCA studies and reports used here were published between 2000 and 2006. The only exception is the results taken from Spadaro et al [10], which were developed in the mid-late nineties in a series of IAEA advisory group meetings to assess the life-cycle GHG emissions for different electricity generating options.

By and large the emphasis is on recent publications only since:

- LCA evolves in detail and complexity since its inception, thereby improving the accuracy of LCA results
- Energy/emission and input/output conditions in upstream and downstream processes change with time due to, for instance, regulation and efficiency improvements [11]
- Technology experience curves potentially render older LCA inappropriate for reference use today, since the associated GHG emissions have fallen, especially for some RETs where the energy pay-back-ratio has improved significantly and continues to improve.

It is important to note that this review has neither judged the quality of recently published LCAs nor systematically compared their consistency (e.g. boundaries or inclusiveness). It is also noteworthy to stress that while some of the studies focused only on GHG, others are to various degrees (much) more comprehensive by quantifying additional external impacts.

For clarification of terms, the sum of the emissions from all life-cycle stages is called *cumulative emission*. All processes and associated emissions but power plant operation are categorised in *upstream* (e.g. fuel exploration, mining, fuel transport) and *downstream* (e.g. decommissioning, waste management and disposal) groups. Emissions from power plant operation are referred to as *direct*. However, the different studies summarised here may use different boundaries (i.e. not consistent) for up- and downstream evaluation of production and energy chains.

3 Direct Emissions from Fossil Fuels

The principle factors determining the GHG emissions from a fossil fuel power plant is the type of technology (and hence choice of fuel) and its thermal efficiency. In addition, thermal efficiency (by and large) increases with the load factor (although efficiency reductions can be observed towards achieving full load operation) and therefore GHG emissions from a particular fossil fuel technology will depend on the mode of its operation (e.g. peak load management, base load supply, combined heat and power supply etc.) [10, 12].

Figure 1 illustrates two graphs. On the left, GHG emissions per kWh_e are depicted for four standard coal technologies (i.e. pulverised fuel (PF), fluidised bed combustion (FBC), integrated coal gasification combined cycle (IGCC) and steam turbine condensing (STC)) and one standard gas power plant type (i.e. combined cycle gas turbine (CCGT)) highlighting that among coal-fired power plants great variations in emissions exist (with the IGCC technology being the best performer), whereas for CCGT technologies the variation is much narrower. With regard to coal fired power plants it is important to note that currently IGCC technology has a comparable efficiency to Ultra Super Critical Pulverized Combustion coal power plants, which is the best available pulverised coal power plant. The large spread that can be observed for PF power plants is due to the fact that only some of the plants analysed here are super critical (in which case emissions tend to be lower) and others are using lignite as a fuel (in which case emissions tends to be higher). The graph on the right shows a strong correlation between GHG emissions and the net thermal efficiency of a coal fired power plant. The data is based on actual emissions from 44 power plants in OECD countries, as well as Bulgaria, Romania and South Africa.

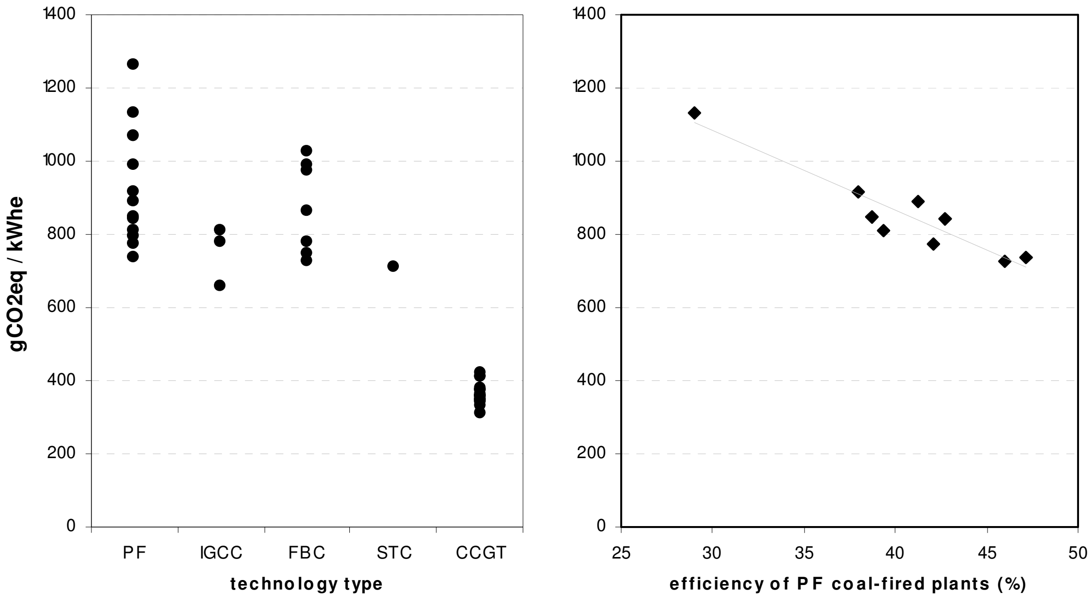

Figure 1: Direct GHG emissions from coal / gas power plant operation
Source: based on data from [13]

In addition to thermal efficiency and plant technology, which in part are intrinsically linked, the carbon content of the fuel plays an important role in determining direct GHG emissions. Figure 2 shows the relationship between the lower heating value (LHV) (i.e. net calorific value MJ/kg) and carbon content per unit of energy. All three series indicate the existence of a correlation that the carbon content increases with a decrease in the net calorific value. The two samples in the top left quadrant represent the reference values for different liquid and gaseous fuels from the Intergovernmental Panel on Climate Change (IPCC) [14], whereas the values in the bottom right quadrant represent different types of hard and brown coal in Europe are adopted from Fott [15]. Subsequently it can be stated that typically *the higher the heating value the lower the carbon content of the fossil fuel.*

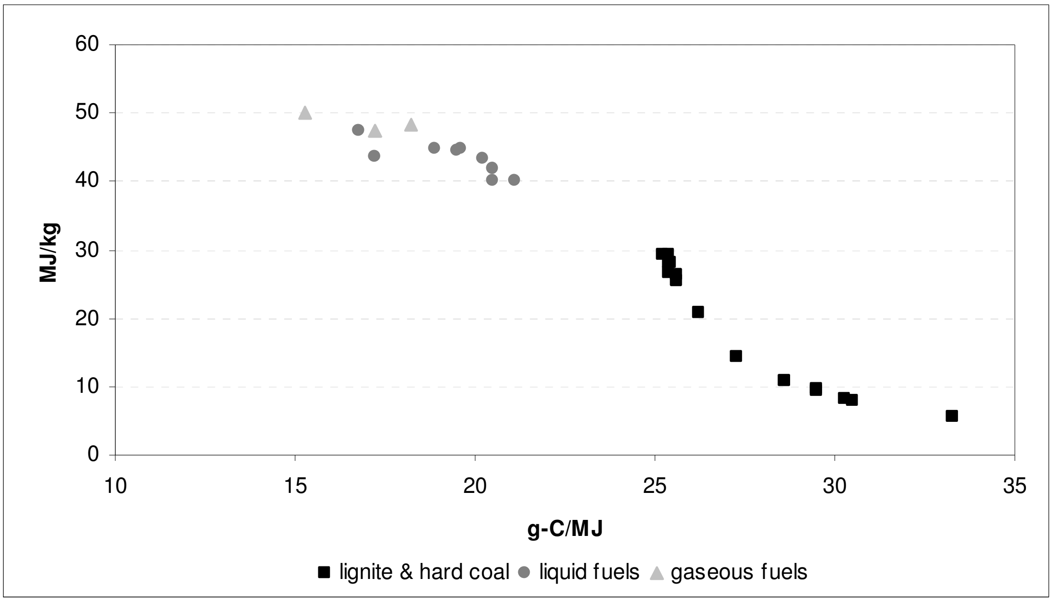

Figure 2: Correlation between heating value and carbon content
Source: based on data from [14, 15]

Figure 3 exemplifies the range of heating values that have been recorded for different fossil fuels for different countries. For example, the LHV in Spain is approximately 20% lower than in Germany. The LHV of lignite in Greece is only 40% of that in Austria, and the LHV of natural gas in the Netherlands is only 80% of the LHV in Algeria and Norway. With regard to Figure 2 & 3 it becomes apparent then, that the origin of the fuel can have a significant impact on the carbon release during combustion.

A similar assessment has been made for Europe by Dones et al [17] – where coal use is from eight regions: Western and Eastern Europe, North and South America, Australia, Russia, South Africa and Far East Asia – recording the lower heating value for hard coal between approximately 18-25.2 MJ/kg, and in the range of 4.7 to 14.9 MJ/kg for lignite.

This section illustrated that direct emissions from fossil fuel power plants are dependent on thermal efficiency, mode of operation, technology type and the carbon content of the fuel. Since more efficient technologies are – at least initially – more costly than less efficient power plants, and fuel with higher heating value pricier than fuels with a lower heating value, it is not surprising to find direct emissions to be lower in countries with higher levels of gross domestic product (GDP) compared with countries of lesser economic wealth. Figure 4 illustrates this assertion showing that the average direct emissions from Annex I[2] and Annex B[3] countries for power plants based on oil, gas and coal are significantly lower than emissions from Non-Annex I[4] countries.

[2] Annex-I are the industrialized countries listed in the annex to the United Nations Framework Conference on Climate Change (UNFCCC) sought to return their greenhouse-gas emissions to 1990 levels by the year 2000 as per Article 4.2 (a) and (b). They include the 24 original OECD members, the European Union, and 14 countries with economies in transition. (Croatia, Liechtenstein, Monaco, and Slovenia joined Annex 1 at COP-3, and the Czech Republic and Slovakia replaced Czechoslovakia.) (Definition based on UNFCCC)

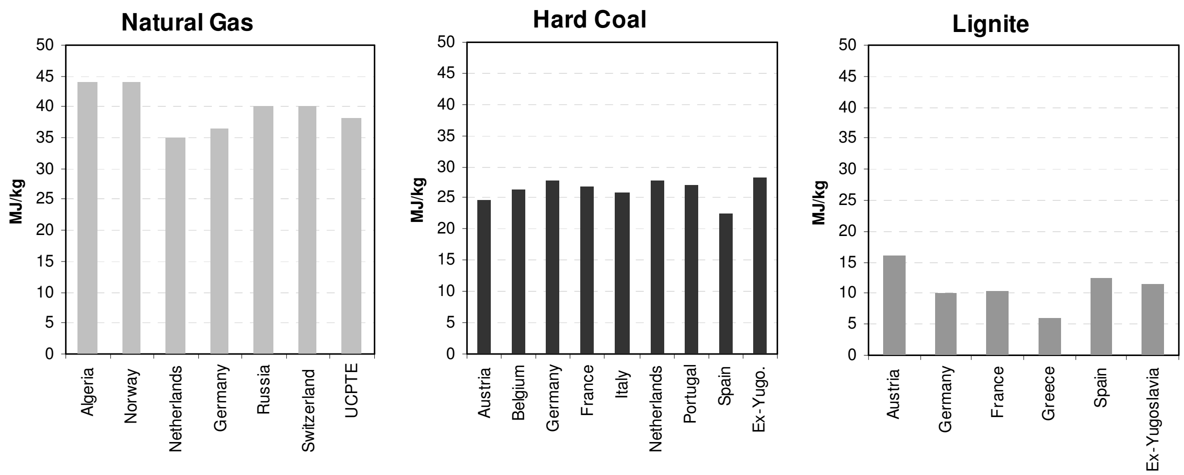

Figure 3: Lower heating values of fossil fuels for selected countries
Source: based on data reported in [16]

What the above analysis shows is that significant variation in direct emissions exists between same fuel technologies due to the various factors introduced above. Quantified emissions are therefore extremely site-specific depending on operating, technology and input conditions of the fuel and can therefore not be generalised to reflect average stack-emissions. Significant variation in emissions can also occur at the upstream and downstream stages of the technology and fuel-cycle from all energy technologies. The following section introduces the methods typically used for assessing full-life cycle impacts.

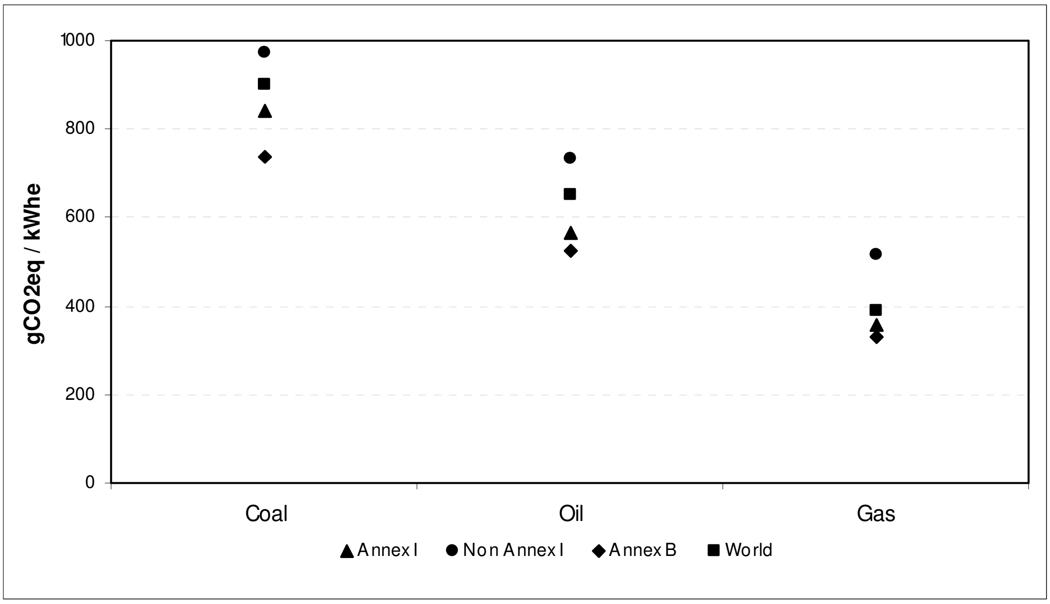

Figure 4: Direct GHG emission of UNFCCC and Kyoto country-groups
Source: based on data from IEA [13]

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[3] Annex-B countries are the 39 emissions-capped industrialised countries and economies in transition listed in Annex B of the Kyoto Protocol. Legally-binding emission reduction obligations for Annex B countries range from an 8% decrease (e.g., various European nations) to a 10% increase (Iceland) in relation to 1990 levels during the first commitment period from 2008 to 2012. Note that Belarussia and Turkey are listed in Annex I but not Annex B; and that Croatia, Liechtenstein, Monaco and Slovenia are listed in Annex B but not Annex I. (Definition based on UNFCCC)

[4] Non-annex-I refers to countries that have ratified or acceded to the United Nations Framework Convention on Climate Change that are not included in Annex I of the Convention. (Definition based on UNFCCC)

4 Assessment Methods

LCA investigates the environmental impacts throughout the full life-cycle of a product or system. Since environmental awareness and regulations are growing, LCA can improve the efficacy of environmental regulation since it can pin-point with great certainty the source of, for example, environmental pollution or resource use of upstream and downstream processes.

GHG LCA can provide information during which stage of the life-cycle significant emissions occur and therefore aid policymakers and stakeholders in focussing efforts where they are most effective in reducing GHG emissions [24]. When deciding between two or more alternatives, LCA can help decision-makers to compare the total cumulative emissions originating from a choice of technologies per unit of electricity. In addition to their use as a tool for decision-making LCA can be used for informing consumers, education, marketing etc. (e.g. environmental labelling, environmental product declaration) [24].

When comparing LCA GHG emission results of various energy chains it is necessary to understand that electricity generating options may not be true alternatives to each other. For instance, services provided by some energy technologies like irrigation and flood control, reliability of supply, and ancillary services such as voltage control, regulation, operating reserve, load-following and system black-start capability may not be easily provided by all technologies [9]. For example, intermittent RETs are not at the same level as other *firm* technologies, since they are rarely able to provide system/network services and may need backup either in the form of energy storage or additional spinning reserves [9, 24].

Furthermore, when using GHG LCA results from energy technologies it should be remembered that all the other biophysical effects and associate impacts of power generation, such as technical performance, cost or political and social acceptance have not been considered, which would be necessary for a truly holistic assessment. For example, common life cycle impact categories in addition to GHG emissions are [25]:

1. Stratospheric ozone depletion
2. Acidification
3. Eutrophication
4. Photochemical smog
5. Terrestrial toxicity
6. Aquatic toxicity
7. Human health
8. Resource depletion
9. Land use

In the case of GHG emissions from electricity generation all significant emissions related to the final product need to be accounted. For electricity this is usually expressed in grams of carbon dioxide equivalent per unit of busbar electricity (i.e. gCO_2/kWh_e). Typically (depending on the type of technology under investigation) LCA would account for GHG emissions at the following stages [18]:

- Energy resource exploration, extraction and processing
- Raw materials extraction for technology and infrastructure
- Production of infrastructure and fuels
- Production and construction of technology
- Transport of fuel
- Other related transport activity (e.g. during construction, decommissioning)
- Conversion to electricity or heat or mechanical energy
- Waste management and waste management infrastructure (e.g. radioactive waste depositories, ash disposal etc.)

LCA methods are generally distinguished between process chain analysis (PCA) and input/output (I/O), although hybrid assessment tools (using elements of both) are also frequently used. Performing an LCA can be resource- and time-intensive, and depending on the system boundaries and the availability of data can greatly impact on the accuracy of the final results [24]. Also, the reliability of LCA results depends strongly on assumptions on lifetime, yield, thermal efficiency, fuel etc.

PCA is a *vertical bottom-up* technique that considers emissions of particular industrial processes and operations and includes a limited order of supplying industries and their corresponding emissions, and is therefore an accurate but resource intensive undertaking. Although, PCA is specific to a particular type of production, and valid only for a well defined system boundary (typically chosen with the understanding that the addition of successive upstream and/or downstream stages may have negligible effects on the total cumulative GHG emissions) [19], it does make the contributing factors to cumulative results more transparent, and modifications through sensitivities easier.

PCA strongly relies on GHG content data being available for all relevant materials and processes [20], when in fact complete material inventories are not always available, and manufacturing data for complete systems difficult to estimate – in which case a hybrid approach could use PCA for material assessments and I/O to derive data for certain system operation and maintenance (O&M), manufacturing steps and other processes where complete information is not available [21]. Although more recently, detailed process analysis LCA data for several products of different sectors are increasingly available through commercial LCA tools [50].

Since PCA cannot practically consider the entire economy it was recognised that PCA carry systematic errors due to the unavoidable truncation of the system boundary resulting in a slight underestimation of energy inputs [19, 22]. However, these errors may be very small. In fact, the uncertainties in the approximations used throughout the complex modelling of different energy chains are likely to be higher than the error for underestimations of likely marginal contributions.

By way of contrast, the I/O method is a *statistical top-down* approach, which divides an entire economy into distinct sectors. Based on economic inputs and outputs between the sectors, I/O generates the energy flows and the associated emissions [17]. For example, an established I/O database provides estimates of the amount of energy required to manufacture classes of products and provides categories of services [21]. However, specific sectors do not exist in I/O table and must be modelled using PCA. In addition, I/O sectors may be too generic, thus not matching the goal of an LCA. Unlike PCA, I/O analysis makes tracking of the 'hot spots' more difficult. Nonetheless, an advantage of I/O is that it does not have a case-dependency as is inherent to PCA, since it deals with aggregates [20], although I/O can inhibit inaccuracies when the actual energy intensity of a process differs from the sector average [20, 22]. For example, LCA based solely on I/O analysis have reportedly produced results that are 30% higher in comparison to results obtained through the PCA method, and in the case of nuclear power the deviation can be up to a factor of two [10].

Therefore, it has been frequently suggested to apply a hybrid approach combining LCA and I/O methods, in which the I/O method is used exclusively for assessing processes of secondary importance, such as energy requirements originating from inputs from upstream supply chains of high order [17, 20].

The main advantages of the hybrid-approach are [24]:

- Allows fast approximation of possible outcome
- Data gaps of PCA can be closed by approximations provided by I/O

Hybrid models therefore allow the boundaries of the analysis to be broadened by accounting for all processes. This is particularly important where a system comprises of many processes and process steps. For fossil fuel power plants the results of a detailed PCA and the hybrid-approach will not differ significantly because the emissions over the whole LCA are dominated by emissions during the operation phase, whereas the life cycle stage is balanced well by both approaches [22]. Although hybrid models are now common they have by no means established themselves as LCA-standard. Especially since the existence and continuous development of sufficiently accurate LCA background databases included in commercial and non-commercial LCA-tools and/or databases (e.g. SimaPro, EcoInvent, U.S. Life Cycle Inventory Database) may revive and further diffuse PCA.

5 Results

This section discusses the results of the assessed LCAs, as well as highlighting the most significant stages of GHG release for the technologies under consideration. *The GHG emission estimates presented here reflect the differences, in for instance, assessment methodology (i.e. I/O, PCA, hybrid),* *conversion efficiency, practices in fuel preparation and transport, technology and fuel choice, the fuel mix assumed for electricity requirements related to plant construction and manufacturing of equipment, and the assessment boundary (i.e. what processes are included in the analysis and which ones are not).* Analysing up-and downstream processes and its associated GHG emissions, which arise upstream and downstream of the power plant (i.e. electricity generation stage), is important since otherwise the GHG emissions resulting from electricity generation of the various fuel options are underestimated. For fossil fuel technology options, upstream GHG emission rates can be up to 25% of the direct emissions from the power plant, whereas for most RETs and nuclear power upstream and downstream GHG emissions can account for over 90% of cumulative emissions.

The matrix in Appendix 1 provides an overview of the key parameters affecting the life-cycle GHG emissions for each of the energy technologies (apart from CCS and energy storage), as well as indicating areas in which improvements in GHG emissions are likely to occur in the future. In the following sections, GHG emissions per kWh_e do not take into account emissions arising from electricity transmission and distribution and are therefore considered net or busbar values.

5.1 Fossil

For fossil fuel technologies the majority of life-cycle GHG emissions arise during the operation of the power plant. As discussed in section 3, the recorded variation of direct emissions is a combination of the carbon/heat content of the fuel, the type of technology and its efficiency. GHG emissions arising during downstream activities are typically negligible. However, upstream GHG emissions between coal, gas and oil can be significant but vary mainly due to the different modes and processes involved in extraction, fuel transportation and fuel-preparation.

Table 1 shows an example of the differences that have been recorded in upstream GHG emissions between fuels and for countries in Europe. Here, it is striking that the upstream GHG emissions from coal and oil (heavy) in Western Europe are approximately 15 and 25 times higher than for lignite. The upstream GHG emissions from natural gas and light fuel oil are even higher. As will be illustrated in the following sections direct emissions from fossil fuel power plants may also vary by an order of magnitude, but only when considering future best performers using CCS technology.

		Min (kg CO_2 eq/kg fuel)	**Max** (kg CO_2 eq/kg fuel)
Hard Coal	At producing region	0.04 (south. America)	0.34 (west. Europe)
	Country specific supply mix	0.188 (Poland)	0.322 (Germany)
	Supply mix UCTE	0.270	
Lignite	At mine	0.017	
Oil	Heavy fuel oil (west. Europe)	0.423	
	Light fuel oil (west. Europe)	0.480	
Nat. gas	West. Europe high pressure grid	0.491	

Table 1: GHG emissions from the upstream chains of fossil fuels used in Europe
Source: [17]

5.1.1 Lignite

The vast majority of the cumulative GHG emissions from lignite power plants occur at the power plant, with no significant contributions from construction, decommissioning and waste disposal. However, during the fuel-cycle noteworthy GHG emissions typically occur. Because of the low calorific value of lignite the fuel masses to be burned are large in comparison to hard coal. Consequently most lignite power plants are mine-mouth, which means that the power plant is situated close to the mine thus not requiring energy intensive transport [18], typically by way of conveyor belt. While the upstream chain of lignite power plants does not have a substantial impact on cumulative results, the upstream chain of hard coal power plants can be an important factor, as illustrated in more detail in the next section. Especially the mining and extraction stages of hard coal can release considerable amounts of methane into the atmosphere, therefore contributing significantly to cumulative life cycle GHG emissions (while lignite has already lost most of its methane in the past due to 'out-gassing'). For example, methane emissions from lignite are calculated to be only about 0.6% of cumulative GHG emissions in UCTE (Union for the Coordination of Transmission of Electricity) lignite chains, while mining activity is estimated to range between 0.9% in France and 2.6 % Greece [17]. Therefore, if full LCA emissions are considered (instead of direct emission only) lignite fares well in comparison with hard coal where transport and coal mine methane emissions add considerable to cumulative GHG emissions.

Figure 5 shows the estimated life-cycle GHG emissions from selected energy technologies based on the literature review carried out in this research. Specifically, the graph shows the mean, the standard deviation as well as the minimum and maximum emissions reported for each technology. With respect to lignite power plants significant variations in cumulative GHG emissions have been quoted in the literature, ranging from approximately 800-1700 gCO_2eq/kWh_e[5]. While cumulative GHG emissions from *future* (up to 2020) and *advanced* (2010) technologies have been estimated to be just over 800 gCO_2eq/kWh_e, *presently* operating lignite power plants have emissions between 1100-1700 gCO_2eq/kWh_e. The great variation in the emissions of current lignite power plants indicates the importance of thermal plant efficiency and operating mode, since most GHG emissions occur at the combustion stage. Significant improvements in the cumulative GHG emissions thus need to focus on the factors affecting direct emissions as discussed in section 3.

5.1.2 Coal

In coal-fired power plants, the largest part of life-cycle GHG emissions arises at the power plant. For *presently* operating plants, emissions at the operating stage range between 800-1000 gCO_2eq/kWh_e,

[5] gCO_2eq/kWh_e = grams of carbon dioxide equivalent per kilowatt hour (electricity)

whereas cumulative emissions for the same plants range between approximately 950-1250 gCO_2eq/kWh_e (see Figure 5).

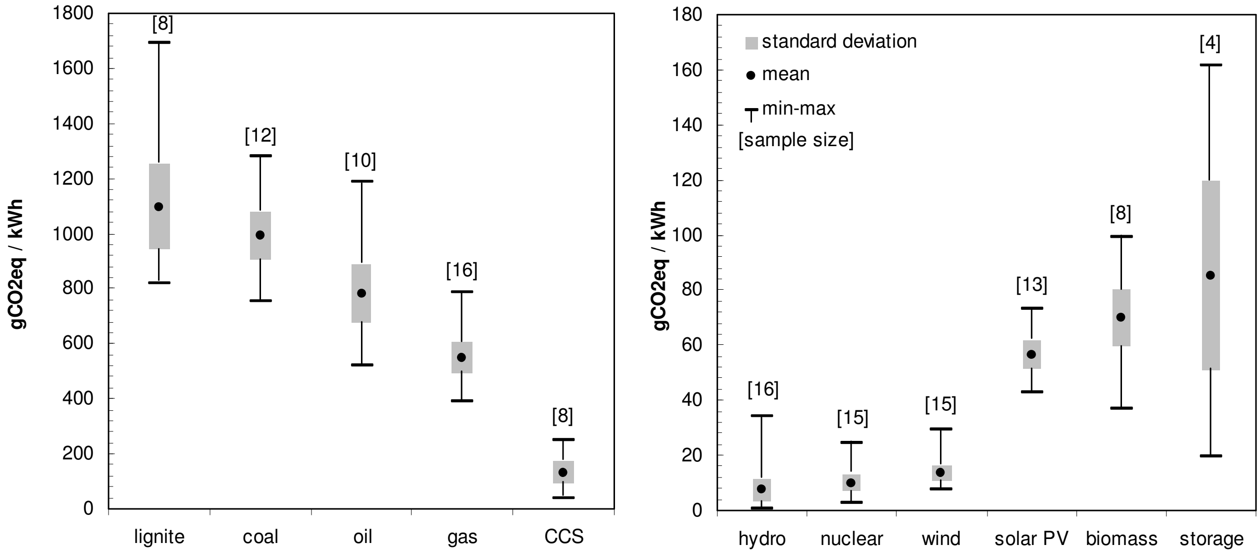

Figure 5: Summary of life-cycle GHG emissions for selected power plants
Source: Lignite [10, 17, 26], coal [10, 17, 22, 26, 27, 28], oil [10, 17, 18, 22, 28], natural gas [10, 12, 17,22, 26, 28, 29, 30], carbon capture & storage (CCS) and energy storage systems [21, 31, 32], nuclear [10, 12, 17, 18, 27, 28, 34, 35], solar PV [17, 26, 28, 36, 37], wind [17, 18, 26, 28, 38, 39, 40, 41], hydro [28, 42, 43, 44], biomass [26, 42, 45

The difference arises at up-and downstream stages, which have been recorded to lie between roughly 50-300 gCO_2eq/kWh_e. While GHG emissions from construction, decommissioning and waste disposal are negligible, emissions relating to coal mining and coal transport can be significant. Dones et al. [17] survey methane emissions to be nearly 7% of cumulative GHG emissions for the UCTE average, while the cumulative upstream GHG emissions from coal in UCTE countries ranges between 8% (Portugal) and 12.5% (Germany). Spadaro et al [10] survey non-direct emissions to be as high as approximately 20% of cumulative GHG emission. The recorded difference in upstream emissions can mainly be attributed to variations in methane emissions from different coal seams. For example, Dones et al [17] record average coalmine methane emissions to range between 0.16g/kg (US open pit) - 13.6g/kg (West Europe) between eight different regions – a difference of two orders of magnitude.

For *future* and *advanced* technologies the total cumulative GHG emissions range roughly between 750-850 gCO_2eq/kWh_e, but require improvements in thermal plant efficiency and methane recovery.

5.1.3 Oil

Most of the GHG life-cycle emissions arise from the operation of the power plant, which range between roughly 700 – 800 gCO_2eq/kWh_e. GHG emissions from power plant construction and decommissioning are negligible, and significant upstream emissions arise mainly at the stages of oil transport, refinery, exploration and extraction, which are in the range of 40-110 gCO_2eq/kWh_e. Dones et al [17] report that on average upstream GHG emissions from oil in UCTE countries are 12% of the cumulative emissions. Cumulative emissions lie roughly between 500-1200 gCO_2eq/kWh_e (see Figure

5). The wide range of GHG emissions does not only depend strongly on technology but also on the different operation of oil fired power plants in European countries (base load vs. peak load).

5.1.4 Natural Gas

The majority of GHG emissions from gas-fired power plants arise during the operation of the power plant and range according to the literature between 360-575 gCO_2eq/kWh_e for present technologies. No significant emissions arise during the construction and decommissioning of the power plant.

However, significant fuel-cycle GHG emissions exist. They are mainly from gas processing, venting wells, pipeline operation (mainly compressors) and system leakage in transportation and handling [22]. Because these factors vary amongst countries, the import structure can be an important factor in determining cumulative emissions. Dones et al [12] report that the leakage rate for transmission of natural gas from the Russian Federation over a distance of 6000km is estimated at 1.4% (with additional leakage in regional and local distribution), whereas energy use in the compressor stations of the pipelines is estimated a further 1.8% of transported gas per 1000km in Europe and 2.7% per 1000km for the Russian Federation. Therefore, the loss rate in the distribution network increases with increases in distance.

In the US, according to the Department of Energy (DOE), nearly 10% of natural gas is lost before reaching the power plant [22] creating significant upstream GHG emissions. Most of this energy loss is due to the compression of a natural gas for transport via pipeline. Transmission operations also lose gas due to leaks from compressor stations, metering and regulating stations, and pneumatic devices. Further losses in the form of fuel combustion and fugitive releases are recorded during processing which prepares natural gas to meet pipeline specifications. A small fraction of the energy loss occurs as the natural gas, consisting primarily of methane, is released directly to the atmosphere from venting wells. While the quantity of atmospheric releases of natural gas (or methane) is often small, it is still significant since the global warming potential of methane is roughly 23 times higher than for carbon dioxide [47].

In Europe, Dones et al [17] estimates that the up-and-down stream emissions from gas-fired generation constitute about 17% of the average UCTE life-cycle GHG emissions in 2000.

In the consulted literature, upstream and downstream GHG emissions from natural gas fired plants lie between 60–130 gCO_2eq/kWh_e for present technologies, with cumulative emissions between 440-780 gCO_2eq/kWh_e. Advanced and future gas-fired power plants are estimated to emit just under 400 gCO_2eq/kWh_e over the full life-cycle with approximately 50 gCO_2eq/kWh_e as non-direct GHG emissions. In order to realise these lower emissions, efforts need to focus on the reduction of gas leakage, improvements of power plant combustion performance and overall plant efficiency [17], as well as pipeline performance.

5.2 Carbon capture & storage (CCS) and energy storage

CCS is defined by the IPCC as a ‘process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere' [31]. Ultimately, the net reduction of emissions depends on the CO_2 capture system (e.g. post- and pre-combustion capture), as well as the transport and the storage options. In its *Special Report on Carbon Dioxide Capture and Storage* (CCS) the IPCC [31] estimates CO_2 (stack) emissions for CCS technology to lie in the range of 92-145 gCO_2/kWh for pulverised coal technology, 65-152 gCO_2/kWh for IGCC and 40-66 gCO_2/kWh CCGT. This is equivalent to a CO_2 emission reduction per kWh in the range of 80-90% depending on technology and fuel. Spath & Mann [32] report higher numbers for CCS mainly due to the fact that supposedly substantial downstream emissions from various energy chains, which cannot be captured by the CCS technology, are included in the analysis. They report 247 gCO_2eq/kWh for a pulverised coal fired power plant and 245gCO_2eq/kWh for a CCGT power plant. While it seems surprising that coal has a similar GHG emission value to gas, Spath and Mann [32] explain this in the higher GHG emission assumptions in the upstream chain for natural gas.

Overall, CCS decreases the net efficiency of a power plant and increases the fuel consumption per kWh delivered to the grid. Dones et al [17] estimates that for CCGT fuel consumption increases by 16-28%, for pulverised coal by 22-38% and coal IGCC by 16-21%, while capital costs increase by 30-50% for IGCC, 70-80% for pulverised coal, and 80-100% for natural gas. Spath & Mann [32] estimate the generating cost for a coal-fired power plant to increase from US$ 0.025 to US$ 0.073 (with 60% of the additional cost necessary for CO_2 capture and compression and the remainder equally shared between the cost of replacement power and the cost of CO_2 transport and storage); and for a new CCGT to increase from US$ 0.045 to US$ 0.075 (with 50% of the additional cost needed for CO_2 capture and compression and the remainder equally shared between the cost of replacement power and the cost of CO_2 transport and storage). The IPCC [31] assumes the cost of electricity production to increase between US$ 0.012-0.024 for CCGT, US$ 0.018-0.034 for pulverised coal, and US$ 0.009-0.022 per kWh for a new IGCC plant. Depending on the value of carbon and a regulatory framework that supports CCS as an abatement technology the additional cost of using this technology may be justified.

Similarly, the use of energy storage in combination with electricity generation increases i) the input of energy required to produce electricity ii) the associated cumulative GHG emissions, as well as iii) the total cost of such a hybrid system. However, cumulative GHG emissions from storage systems when operated in combination with low-carbon technologies, such as nuclear or renewable technologies, can be substantially lower than from fossil fuel derived electricity. Using storage may also be desirable for eliminating the intermittent nature of some renewables thereby being able to provide dispatchable grid services or to provide power at peak power demand to receive higher electricity sales revenues [21].

Therefore, GHG LCA of storage systems can provide a basis for comparison of the cumulative GHG emission between, for instance, intermittent renewables and firm energy sources (ibid.).

Figure 5 summarises the life-cycle GHG emissions based on a study by Denholm and Kulcinski [21] for four energy storage systems using a PCA for most material assessments and an I/O analysis to derive data for certain system aspects where information is not available. Compressed Air Energy Storage (CAES) and Pumped Hydro Storage (PHS) are considered mature technologies and significant improvements in both energy input and efficiency are unlikely in the near future, whereas the Battery Energy Storages (BES) systems (i.e. Vanadium Redox Battery (VRB) and Polysulfide Bromide Battery (PSB)) presented here are still under development and significant cost and efficiency reductions can be expected [21].Presently, BES has higher GHG life-cycle emissions than CAES or PHS with the vast majority of emissions relating to power stack materials and manufacturing, as well as balance-of-plant. The life-cycle GHG emission *per kWh of storage capacity* is reported to be 19 gCO_2eq for CAES, 36 gCO_2eq for PHS and 125 and 161 gCO_2eq for PBF and VRB respectively. It is therefore important to emphasise that, depending on the source of electricity used for energy storage (i.e. high or low carbon intensity per kWh), energy storage can add significantly to the GHG emissions of an electricity supply system.

5.3 Nuclear

Differences in the GHG emissions for nuclear energy chains, amongst others, can be attributed to the enrichment technology used, as well as the nuclear energy technology type (e.g. Pressurised Water Reactor (PWR), Boiling Water Reactor (BWR)). For example, enrichment using diffusion technology rather than centrifuge technology is more energy intensive and depending on GHG emissions relating to the electricity supply mix of the country where enrichment is taking place can significantly impact on the cumulative GHG life-cycle. A typical chain for nuclear would, for example, consist of uranium mining (open pit and underground), milling, conversion, enrichment (diffusion and centrifuge), fuel fabrication, power plant, reprocessing, conditioning of spent fuel, interim storage of radioactive waste, and final repositories [17]. The studies summarised in this section have investigated the GHG life cycle emissions only for Light Water Reactors (LWR) (i.e. PWR and BWR), which is the most widespread and commonly used reactor technology.

For LWR GHG emissions during the operational stage of the reactor, relative to cumulative life-cycle emissions, are of secondary importance – ranging between 0.74 – 1.3 gCO_2eq/kWh_e. Unlike fossil fuel powered technologies the majority of the GHG emissions arise at the upstream stages of the fuel and technology cycle with values roughly ranging between 1.5 –20 gCO_2eq/kWh_e. The notable difference in the upstream emissions is mainly due to the enrichment process, with significantly higher emissions for diffusion technology and lower values for centrifuge technology if the associated electricity consumption is of fossil origin, as well as whether the fuel-cycle is 'once-through' or 'recycled'.

However, it is important to note that centrifuge technologies are presently the technology of choice and are believed to substitute diffusion technology in the future which currently have about 40% of the market output (i.e. enriched uranium) [33]. The GHG emissions associated with downstream activity, such as decommissioning and waste management, range between 0.46-1.4 gCO_2eq/kWh_e. Cumulative emissions for the studies under consideration lie between 2.8-24 gCO_2eq/kWh_e, as shown in Figure 5. Dones et al [17] suggest that in order to reduce emissions from nuclear technologies key areas of improvement would be to:

- Reduce electricity input for the enrichment process (e.g. replacement of diffusion by centrifuges or laser technologies)
- Use electricity based on low or no-carbon fuels
- Extend lifetime and increase burn-up

GHG avoidance at the operating stage of the nuclear power plant is minimal since its contribution to the cumulative GHG emissions is already small.

5.4 Renewable Energy Technologies

In contrast to fossil fuel technologies, the vast majority of GHG emissions from RETs occur upstream of the plant operation – typically for the production and construction of the technology and/or its supporting infrastructure. Although for biomass systems the majority of emissions can arise during the fuel-cycle depending on the choice of biomass fuel. For intermittent technologies the question arises whether or not life cycle analyses should include the GHG emission resulting from required backup services, such as spinning reserve, or not. Principally this is yet not included in the studies provided.

5.4.1 Photovoltaic

Figure 5 summarises the results from various life-cycle studies for photovoltaic systems, which range between 43-73 gCO_2eq/kWh_e. Typically four systems have been assessed: mono-crystalline, poly-crystalline, amorphous and CIGS (Copper Indium Gallium Diselenide). Unlike fossil fuel systems most of the GHG emission occur upstream of the life-cycle with the majority of the emissions arising during the production of the module (between 50-80%). Other significant GHG releases in the upstream relate to the balance-of-plant (BoP) and the inverter. Operation, end-of-life and associated transport activities do not result in meaningful cumulative GHG emissions. Of the four systems, mono-crystalline plants, on average, may emit the least GHGs ranging between 43-62 gCO_2eq/kWh_e. The other PV systems may emit between 50-73 gCO_2eq/kWh_e over the whole GHG life-cycle. Variations in the results can be for a range of factors, such as the quantity and grade of silicon, module efficiency and lifetime, as well as irradiation conditions. Differences in installation, such as integrated and non-integrated systems, as well as facade, flat roof and solar roof tiles, or the efficiency of the peripheral equipments, such as the balance-of-system (BOS), also significantly affect lifecycle GHG emissions in the presented case studies. It is also important to note that the studies summarised here are based on different assumptions of solar radiation (due to different geographies), solar panel orientation and angle. Future improvements in cumulative GHG emissions from PV are likely to arise from improvements in module efficiency, increased lifetime, less silicon mass per module and lower use of electricity for the production process. In this regard it may be important to note that solar PV technology is a relatively fast-improving technology and new LCA studies are frequently being published in order to keep the pace with the advancements (this is also true for other RETs such as wind turbines).

5.4.2 Wind

For wind turbines most of the GHG emissions arise at the turbine production and plant construction, which vary between 72-90% of cumulative emissions. Significant differences lie mainly in the foundation of the power plant. For instance, offshore wind turbines require significantly higher amounts of steel and cement than an on-shore counterpart for construction. For onshore plants however most of the GHG emissions relate to the turbine production (mainly for the tower and the nacelle). GHG emissions not related to construction and production arise during operation & maintenance, decommissioning, transport of materials and turbine, and range between 10-28% of cumulative emissions.

Typically, larger turbines – under similar wind conditions – have lower life-cycle GHG emissions than smaller turbines, whereas offshore turbines have higher emissions than onshore turbines given equal capacity factors (or wind conditions), due to the high level of emissions associated with the foundation, connection and erection for off-shore turbines [17]

LCA GHG emissions from wind turbines are very site-specific and sensitive to wind velocity conditions, because of the cubic relationship of wind velocity to power output. Since wind regimes vary significantly with geography different capacity factors used in the studies add to the variation that can be observed in the results, which lie between 8-30 gCO_2eq/kWh_e for onshore, and 9-19 gCO_2eq/kWh_e for off-shore turbines (see Figure 5). Since wind turbine technology is rapidly improving the accuracy of LCA results have only a limited lifespan since these improvements can significantly alter the outcome of such a study. Improving the lifetime of a wind turbine, for example, can drastically reduce the LCA values (which is also true about different LCA studies assuming different lifetimes at the inception of their study).

5.4.3 Hydro

In the majority of the analysed cases most of the GHG emissions typically arise during the production and construction of the hydroelectric power plant (especially for reservoir dams). In the illustrated cases emissions for construction and production roughly lie between 2-9 gCO_2eq/kWh_e. However, in some cases hydro power plants that use reservoirs can emit significant quantities of GHGs that easily surpass all other GHG emissions in the energy chain, due to land-clearance prior to construction but especially due to flooding of biomass and soil. For example, flooded biomass decays aerobically – producing carbon dioxide – and anaerobically – producing both carbon dioxide and methane [21]. The amount of GHG release depends on reservoir size, type and amount of flooded vegetation cover, soil type, water depth, and climate. As reported by Bauer [44] for European examples, these releases can vary considerably depending on the specific GHG releasing characteristics - as discussed above - and lie between 0.35 gCO_2eq/kWh_e for reservoirs in the alpine region and on average 30 gCO_2eq/kWh_e for reservoirs in Finland, although peat soils have reportedly higher GHG releases[6].

Overall, the life cycle GHG emissions for the assessed cases range between approximately 1-34 $gCO_2eq/kWh_{e,}$, as shown in Figure 5, depending on the type of plant (run-off or reservoir), its size and usage (e.g. pumped hydro), as well as the electricity mix (and hence emissions) used for its operation. However, it is important to emphasise that the emission results from pumped storage, run-of-river and reservoir do vary significantly. In fact, the life-cycle GHG emissions from pumped hydro can be significantly larger than the values quoted here when the electricity used to pump/store water is generated from fossil fuel based technologies (see also section 5.2)

5.4.4 Biomass

Life-cycle GHG emissions from biomass systems mainly depend on the energy intensity of the fuel-cycle, the bio-fuel properties, as well as the plant technology and its specific thermal conversion efficiency. The range of life-cycle GHG emissions for the studies given in Figure 5 lie between approximately 35-99 gCO_2eq/kWh_e. The majority of emissions arise at the fuel-cycle stage, while GHG emissions during the other stages of the life-cycle are negligible. Biogenic GHG emissions (emissions arising from the combustion of biofuel) are not included in the Figure since they are believed to be carbon neutral. Generally the use of biomass at the electricity generation stage is defined as a 'carbon-neutral' because the CO_2 released during combustion is absorbed during (fuel-) plant growth. Life-cycle emissions for biomass systems vary substantially depending on the combustion efficiency, power rate and the type of feed (e.g. chips vs. logs vs. pellets vs. gas).

More recently publications on GHG emissions from the growth of different energy fuels have emerged, but for consistency and comparability only wood-based fuels have been quoted here.

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[6] Dones et al [17] report of two additional research studies from Canada and Brazil. Canadian research concluded that reservoirs in tropical regions (where biodegration is faster) emit approximately 5 and 20 times more GHG than in boreal and temperate regions. This translates into average GHG emission factors of 10-60 gCO2eq/kWhe for boreal and temperate reservoirs and 200-3000 gCO2eq/kWhe for tropical reservoirs. Similar results were presented from the Brazilian researchers who found that using the average capacity factor for seven Brazilian hydroelectric plants results in an interval of direct reservoir emissions of 12–2077 gCO2eq/kWhe averaging at approximately 340 gCO2eq/kWhe

6. Discussion and Concluding Remarks

The life-cycle analyses presented here indicate for some cases the existence of significant upstream emissions (e.g. up to 25%) that may arise outside the legislative boundaries of a national GHG mitigation programme / regulation. Consequently, electricity generation and use in one country may result in significant GHG releases in another.

For example, increasing demand for gas-fired power plants in the UK (as a result of market liberalisation) has substantially lowered GHG intensity in the UK power sector. As an Annex B party to the Kyoto Protocol this so-called 'dash-for-gas' has significantly aided the UK's efforts in achieving its Kyoto obligations (although this has happened for different reasons). However, with an (expected) increasing share of natural gas to be imported to the UK – due to dwindling North Sea Gas reserves – from countries outside Annex B (e.g. Middle East, North Africa) [48, 49] upstream emissions from natural gas sourcing, processing and transport will be arising outside Britain's GHG accounting[7]. For now, gas exporters such as Middle Eastern countries have no GHG emissions constraints. This so-called 'leakage' effect would therefore lessen the GHG emission improvements made in the UK since leakage between Annex B and non-Annex B countries is presently not counted against the emission reduction targets of Annex-B countries.

Since upstream GHG emissions can be up to 25% of cumulative emissions it would be desirable to develop a system or compliance mechanism that can capture/account for upstream (and downstream) releases of GHG across a range of spatial scales in order to identify (un-)intended leakages – not only to make climate policy more effective and holistic but also to level the playing-field for technologies that do not have significant indirect emissions. In the case of fossil fuels, indirect emissions can be as high as 300 gCO_2eq/kWh_e, while for renewable and nuclear energy technologies cumulative indirect GHG releases are typically lower than this number by an order of magnitude.

Globally the power sector is responsible for a large share of present-day GHG emissions. In 2002, power and heat generation contributed to roughly 40% of global GHG emissions (which are likely to be higher if the life-cycle emissions were considered) while transport, for example, contributed to about 20% [51]. The *Reference Scenario*[8] of the IEA's 2006 World Energy Outlook projects that power generation will contribute to half of the increase in global carbon dioxide emissions between 2004 and 2030 [52]. Therefore, mitigation strategies that can effectively reduce GHG emissions from

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[7] Liquefied Natural Gas (LNG) imports - although not analysed here - requires 7-10% of gas delivered for liquefaction increasing the upstream chain GHG emissions (comparable to several thousand km pipeline transmission).

[8] The *Reference Scenario* takes account of those government policies and measures that were enacted or adopted by mid-2006, though many of them have not yet been fully implemented. Possible, potential or even likely future policy actions are not considered.

electricity generation may play a pivotal role in meeting countries' obligations under the Kyoto Protocol and the UNFCCC.

While there are technology winners with regard to life-cycle GHG emissions in electricity generation - this literature review has shown that RETs and nuclear have lower life-cycle GHG emissions than fossil fuel technologies - it is important to realise that RETs and nuclear energy may not be available at sufficient quantities at competitive prices or not acceptable on social or political grounds to begin dominating power supply in the short- to medium-term. In fact, the social, political, economic and infrastructural reality of meeting growing energy needs is likely to require the pursuit of a combination (if not all) of GHG mitigation policies to help reduce the GHG intensity from power sector activity.

The following discussion focuses on carbon mitigation options, with a view of identifying policies that are likely to improve the carbon intensity in the power sector on a global scale against the backdrop of a rapidly increasing electricity demand.

Broadly speaking five carbon-mitigation options exist for the power sector as identified – amongst others – by Sims et al [46]:

1. *More efficient conversion of fossil fuels*

   In the cases presented for coal-fired power plants (see section 5.1.2), for example, thermal plant efficiency varies between roughly 30-50% with nearly twice the GHG emissions for low efficiency plants compared to most efficient plants. This shows that coal-based technology has a large GHG emissions reduction potential. However, in the short- to medium-term this requires market and regulatory frameworks that encourage investments in the latest technologies that will improve the efficiency of coal-fired electricity generation and thus reduce specific CO_2 emissions [53]. China, for example, the world's biggest user of coal for electricity generation could use approximately 20% less coal if its power plants were as efficient as the average power plant in Japan today [54]. Similarly, Russia the world's biggest user of natural gas for electricity generation could use a third less gas, if its power plants had the same average efficiency as Western European gas-fired power plants (ibid.). Since coal and gas together had a combined share of 60% in global electricity generation in 2004, which according to the IEA's 2006 World Energy Outlook is projected to increase to 67%, policies need to create conditions that make the adoption of highly efficient fossil fuel power plants lucrative to investors and markets [52].

   Figure 5 shows that the variation in life-cycle GHG emissions for each fossil fuel technology is significant - the difference between the best and worst performer is typically at least double, and the difference between the best performer and the mean typically at least 30% lower. Since the majority of GHG emissions is at the electricity generation stage large savings can be made from applying best performance technologies, as suggested by the above examples.

2. *Switching to low-carbon fossil fuels and suppressing emissions generated*

The summary results given in Figure 5 show that switching from coal (especially lignite) and oil towards using best available technologies in gas generating plants can lead to GHG emissions savings (e.g. average life-cycle GHG emissions from gas fired plants are approximately ½ of lignite/coal fired power plants) . However, it needs to be recognised that switching from one technology/fuel to another represents only a technical option. The underlying economic reality will determine whether this option is used (e.g. the switch from coal/lignite to gas will only be done when the price is right). Furthermore, switching from coal/lignite to gas on a substantial scale can lead to upward pressure on the gas price potentially eroding the economic benefit of gas. In addition, switching from one fuel to another is likely to require further investment to develop a supportive infrastructure that facilitates fuel switching. For example, switching from coal to gas may require additional gas pipelines and LNG/LPG terminals to accommodate the expansion of gas fired power plants. The additional cost to develop such an infrastructure may also render fuel switching uneconomic - unless regulatory or investment assistance facilitates the use of low-carbon fossil fuels. .

3. *Increasing the use of nuclear power*

From a GHG emission perspective nuclear power plants (i.e. LWR) are very attractive since they have a huge GHG life-cycle reduction potential when displacing fossil fuel fired power plants, as well as the ability to provide energy services similar to most fossil fuel based energy technologies[9]. Figure 5 shows that on average LWRs have the second lowest life-cycle GHG emissions of all assessed technologies

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[9] While nuclear power plants are typically base load power plants, and some are being used in load-following mode (e.g. France, Japan), they are not appropriate as peaking/balancing power plants.

However, in many countries nuclear power is socially and/or politically not acceptable which clearly limits its global GHG reduction potential. In countries where nuclear power is acceptable, governments have to play a stronger role in facilitating private investment, especially in liberalised markets, if nuclear power is to play a more important role in the future [52]. For example, in its *Alternative Scenario*[10] the IEA projects that nuclear power is going to provide approximately 14 % of electricity in 2030 (down from 16% in 2004) [52] - indicating the limitation of nuclear power to reduce GHG emission intensity from the power sector in the medium-term.

4. *Increasing the use of renewable sources of energy*

Figure 5 shows that greater use of RETs can significantly reduce the carbon intensity of electricity generation in power sectors that are dominated by fossil fuel power plants.

However, renewables are unlikely to meet the present and forecasted energy demands at reasonable cost (as suggested in most literature), nor are intermittent RETs able to provide necessary network services that fossil fuel technologies can (e.g. frequency control, regulating and balancing power). The significant expansion of intermittent or distributed renewables may also require advances in grid management and network upgrading, as well as energy storage or other forms of back-up capacity, which can impose additional costs and emissions on their operation. Although, the combined life-cycle GHG emissions from the hybrid/joint operation of RETs and energy storage, which can improve the availability of intermittent RETs, can still be lower compared to CCS this depends crucially on the carbon intensity of the electricity used for providing energy storage.

In its most optimistic medium-term projection, the IEA projects that the electricity share from renewables is to increase from 18% in 2004 to 26% in 2030 - of which the majority of the marginal increase is hydro [52]. The global potential for RETs in improving the emissions intensity from RETs therefore seems limited in the medium-term.

5. *Decarbonisation of fuels and flue gases, and CCS*

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[10] The *Alternative Policy Scenario* analyses how the global energy market could evolve if countries were to adopt all of the policies they are currently considering related to energy security and energy-related CO2 emissions.

Section 5.2 indicates that the adoption of CCS technologies could lead to substantial reductions in life-cycle GHG emissions (e.g. at least 2/3 and ½ for coal and gas respectively) but at yet high cost penalties. While in the future, technology learning is likely to bring down the present cost penalty of CCS, in the short- to medium term substantial financial incentives and more RD&D will be needed [54]. Higher market prices of carbon certificates may also improve the economics of CCS. However, Figure 5 shows that, although CCS can lead to a reduction in the life-cycle GHG emissions of fossil fuels, they are still higher than for nuclear power plants and RETs.

Nonetheless, since - on a global level - RETs and nuclear are unlikely to be able to provide electricity at the scale needed to meet growing electricity needs, CCS may well become a sought-after intermediate technological solution. Especially in view of the fact that the projected marginal demand increase for heat and power by 2030 is expected to be met by 75% from fossil fuels [52]. Given the medium-term global energy needs the application of CCS bears significant potential in limiting/reducing GHG emissions from the power sector.

All the above options can aid countries in reducing the GHG emissions intensity from power production at a national level from an energy supply perspective. For example, in the *Alternative Policy Scenario* of the 2006 World Energy Outlook, the IEA [52] projects CO_2 intensity improvements of electricity generation, such as the increased use of nuclear power and renewable energy technologies, to contribute to 22% of the avoided CO_2 emissions (in comparison to the *Reference Scenario*) by 2030. Improved efficiency and fuel switching in the power sector would lead to global savings in CO_2 emissions of 13% under the same conditions.

However, it is also important to note that many demand side management (DSM) options can reduce electricity demand (and hence emissions) more effectively than altering energy supply patterns. According to the IEA's *Alternative Policy Scenario* demand side policies that encourage more efficient use of electricity, such as in lighting, air conditioning, electrical appliances and industrial motors, contribute to roughly 30% of the avoided CO_2 emissions in comparison to the *Reference Scenario* by 2030 - nearly as much as the combined GHG mitigation potential from the power sector supply side.

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Appendix 1: Specific parameters affecting LCA results

	Fossil Fuels	Hydropower	Biomass	Nuclear (LWR)	Wind	Solar PV
Key Parameters affecting results	- Fuel characteristics (e.g. carbon content and calorific value) - Type of mine and location - Fuel extraction practices (e.g. affect transport and methane release) - Energy carrier transmission/transport losses (e.g. pipeline) - Conversion efficiency - Fuel mix for electricity needs associated with fuel supply and plant construction / decommissioning - Installation rate and efficiency of emission control devices -Lifetime and load factor	- Type of plant (e.g. run-of-river, reservoir) -Size, depth and location of reservoir affect CH_4 release - Energy use for building dam - Lifetime	-Feedstock properties (e.g. moisture content, heating value) and eventual pre-treatment - Processing of feedstock (e.g., gasification and following transport to power unit) - Energy use for feedstock requirements (growth, harvesting, and transport) - Plant technology - Plant conversion efficiency - Lifetime	- Energy use during fuel extraction, conversion, enrichment and construction / decommissioning - Fuel enrichment by gas diffusion or centrifuge (i.e. diffusion requires more energy by an order of magnitude) - Emissions from the enrichment step since they depend on country-specific fuel mixes and/or plant-specific power supply - Fuel reprocessing, open/closed cycles - Lifetime	- Tower and nacelle (onshore) - System foundation and tower (off-shore) - Electricity mix and construction regulations - Wind conditions (i.e. capacity factor or full load hours per year) - Lifetime	- Quantity and grade of silicon used for manufacture - Type of technology - Type of installation (e.g. slanted and flat rooftop, façade) - Fuel mix for electricity requirements throughout the entire production chain. - Module efficiency and assumed lifetime - Location and irradiation conditions - BOS materials and efficiency - Lifetime - Allocation of resources/emissions assumed in the LCA for high (electronic and/or solar) grade silicon production for PV manufacturing
Likely areas for improvements	- Increased methane recovery in underground mining - Improvements in power plant abatement technology - Improving the thermal efficiency of power plant - Reduction of natural gas leakage - Improvements of power plant burner performance - Improvements in pipeline performance	- Improvements in overall plant efficiency - Improved understanding of GHG emissions from reservoirs - hydro management	- Improvements in plant technology and efficiency - Improvement in feedstock properties	- Reductions of electricity consumption in enrichment by replacement of diffusion by centrifuges or laser technologies - Switching from high to low carbon electricity sources can significantly reduce the GHG emissions at the enrichment phase, especially for energy intensive diffusion technology. - Power plant improvements particularly extended lifetime and increased burn-up	- Improved off-shore foundations / towers (e.g. mono-pylon, tripod etc.), as well as light-weight material improvements may improve GHG emissions in the construction phase but requires additional research. - Improved efficiency & size	- Higher cell and module efficiency and lifetime - Lower specific use of Si Mass and lower Si losses during production - Lower electricity consumption throughout the entire production chain

Source: based on 10, 17, 18, 37