Life cycle environmental impact assessment of coupled underground coal gasification and CO_2 capture and storage: Alternative end uses for the UCG product gases

Anna Korre, Sevket Durucan*, Zhenggang Nie

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Abstract

Underground coal gasification (UCG) has the potential to provide a source of energy or chemical feedstock derived from coal seams, where traditional mining methods are not suitable or are uneconomical. This paper presents the life cycle inventory models developed for the UCG processes and three alternative syngas utilisation options with and without CO_2 capture and storage. The paper compares the life cycle carbon footprint of two different conventional above ground coal fired power generation options with UCG Integrated Gasification Combined Cycle power generation with/without CCS for two different lignites and one bituminous coal. One of the lignites is then used to compare the life cycle performance of different syngas utilisation options: power generation, ammonia production with power generation, and methanol production with power generation. It was found that the life cycle carbon footprint of conventional above ground coal fired power generation is very much dependent on the in-situ methane content of the coal used, and methane emissions experienced during mining and accompanying upstream processes, whereas the same for UCG-IGCC power depends more on the process dependent syngas composition. UCG methanol production with associated power and CCS is shown to release more life cycle CO_2-eq emissions per tonne of lignite consumed than that of UCG ammonia production with associated power and CCS and UCG CCGT power generation with CCS. Furthermore, when chemicals production from UCG is considered as the main objective, the most substantial improvements in comparison to conventional methods are associated with UCG ammonia process per tonne of chemical produced.

Keywords

Life cycle assessment, life cycle inventory modelling, underground coal gasification, CO_2 capture and storage, syngas utilisation

Highlights

- The lower energy content lignite produced a syngas with comparatively better energy efficiency.
- Life cycle carbon footprint of UCG-IGCC plants depends more on the process driven syngas composition rather than the in-situ methane content.
- Life cycle carbon footprint of conventional above ground coal fired power generation depends on the in-situ CH_4 content and mining CH_4 emissions.
- Bituminous coal UCG-IGCC plants have a greater life cycle carbon footprint than that of lignite UCG-IGCC plants.
- UCG methanol production and CCS releases more life cycle CO_2-eq emissions than UCG ammonia

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1. Introduction

Coal currently accounts for 27% of global primary energy supply. It is estimated that global coal consumption will peak before 2020, and flatten at around 5,500 Million tonnes of coal equivalent over the period from 2016 to 2040 (IEA, 2017). The main driver of CO_2 emissions growth over 2000-2016 has been the use of coal for power generation (IEA, 2017) and the power sector being considered as the principal focus of decarbonisation efforts. Nevertheless, Carbon Capture and Storage (CCS), the key CO_2 emission mitigation technology for coal power generation, has made limited progress in demonstrating its commercial viability so far, mainly due to high costs and long periods of return on investment (IEA, 2017; Nie et al., 2017; Korre et al., 2014). Underground Coal Gasification (UCG) coupled with CO_2 capture and storage has been considered as a promising option for the future of coal power generation (Perkins, 2018; Yang et al., 2016; Camp and White, 2015), as it has the potential to not only reduce environmental impacts such as GHG emissions, ash residues, etc., but it can also eliminate processes such as coal mining, coal handling, and coal transport, as well as replacing surface coal gasifiers by more modest infrastructures and operational facilities (Bhutto et al., 2013; Burton et al., 2013; Pana et al., 2009). In particular, UCG can utilise coal seams which are deep or unmineable by conventional mining methods. Furthermore, under some geological settings and storage options, there may be an advantage in coupling UCG with CCS due to potential savings in CO_2 transport costs (Self et al., 2012; Roddy and Younger, 2010; Friedmann et al., 2009).

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Underground coal gasification is an in-situ gasification process carried out within coal seams using injection of oxidants and bringing the combustible gas to surface through production wells drilled from the surface (Figure 1). It has the potential to provide a source of energy or chemical feedstock derived from coal. In brief, UCG involves:

i) drilling an injection well into the coal seam and linking it with a production well by a channel through which gases can flow;
ii) igniting the coal seam;
iii) injecting an oxidant (e.g. air, oxygen/steam etc.) via the injection well to the in-situ gasification chamber/reactor;
iv) receiving product syngas from the production well;
v) moving the injection point further and exposing new coal each time the quality of the product gas is declined in the reaction zone.

Depending on the UCG technology used, this process continues until the length or coverage of the boreholes in coal is exhausted (Perkins, 2018; Camp and White, 2015; Burton et al., 2013).

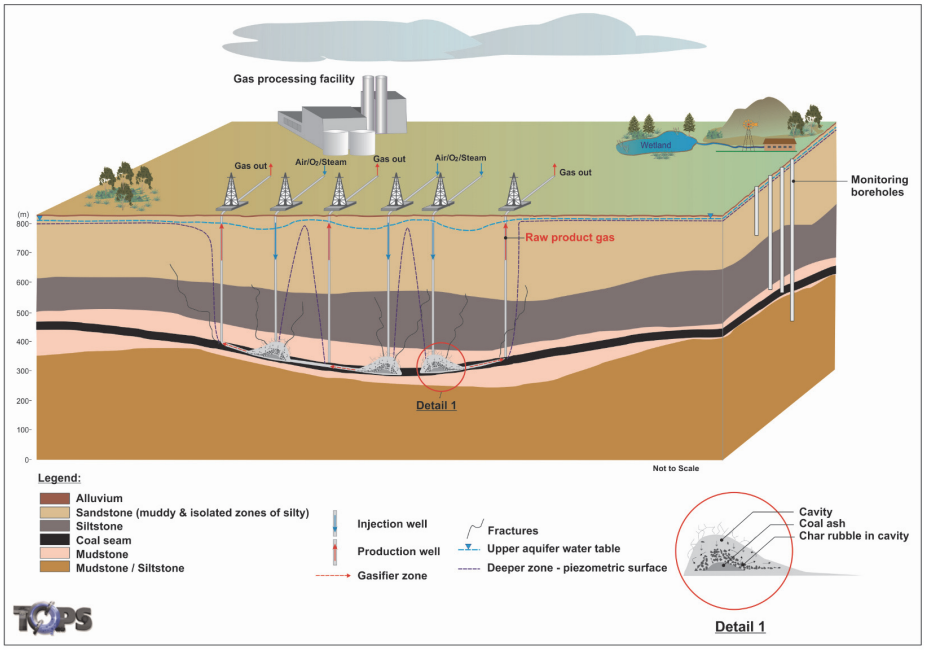


Figure 1. Schematic diagram of underground coal gasification field implementation (Courtesy of the TOPS UCG-CCS Project).

Approximately one hundred experimental, pilot and demonstration UCG trials have been carried out globally in the last eighty years (Waters and Milne, 2018; Camp and White 2015; Durucan et al., 2014; Burton et al., 2013; Hyder, 2012). These have demonstrated that UCG is technically feasible and the understanding of UCG processes, UCG technologies and monitoring methods have continually improved (Waters and Milne, 2018; Camp and White 2015).

The product syngas from UCG can be utilised in alternative processes such as: i) generation of electricity by combustion of syngas in a combined cycle gas turbine plant; ii) conversion of syngas into methanol, which may be further refined into dimethyl ether, olefins and acetic acid or combusted as a fuel additive; iii) conversion of syngas to ammonia and/or urea; iv) conversion of syngas to hydrogen for use in fuel cells; v) conversion of syngas into synthetic natural gas by methanation reaction; vi) conversion of syngas into synthetic crude oil to produce naphtha, diesel and kerosene via the Fischer-Tropsch process. In recent years, a number of researchers investigated the technical feasibility of combining underground coal gasification with CO_2 capture and storage as a potential option to mitigate against the climate change impacts of CO_2 emissions (Burton et al., 2013; Roddy and Younger, 2010; Kempka et al., 2009; Blinderman and Friedmann, 2006).

With respect to environmental performance, UCG processes generate compounds that could become contaminants if they escape the gasification chamber into the surrounding environment. The potential environmental impacts of these contaminants depend on background contaminant levels, the spread of the

contaminant and their fate in the environment, as well as the possibility to reach vulnerable receptors. There are essentially two types of contaminants produced by UCG, direct (or primary) and indirect (or secondary). Direct production of contaminants can be classified as: i) condensable organic contaminants such as tars (heavy organics), partially oxidised organics (organic acids, phenols, etc.), and nitrogen or sulphur-containing compounds (pyridines, aniline, carbonyl sulphide, etc.), which come mainly from the pyrolytic decomposition of coal (pyrolysis) and subsequent reactions in the gasification process, and ii) non-condensable inorganic contaminant species, such as hydrogen sulphide (H_2S) and ammonia (NH_3) (Camp and White, 2015). Contaminants produced indirectly (often later in the process) are due to increased temperature, changed pH, and/or other physical or chemical changes to the system, which can mobilise or increase concentrations of various contaminants, such as minerals and metals (when solubility increases due to changes in oxidation state within the ash and rock or changes in pH) (Waters and Milne, 2018; Camp and White, 2015). Many organics produced are broken down completely or converted into compounds, which are potentially less hazardous to the environment during the UCG processes and within the contained gasification chamber (Waters and Milne, 2018; Camp and White, 2015). Under conditions where these contaminants in the UCG product gas leak to surrounding environments through porous media and fractures underground, contaminants would be deposited within the host rock and affect the groundwater along the leakage pathway in a "chromatographic" fashion. This means that the higher boiling point, more water-soluble, and more readily sorbed species will leave the gas stream first, and thus be found closest to the leakage point and, similarly, lower boiling point, more water insoluble, and less readily sorbed species will remain in the gas phase longer and travel further (Camp and White, 2015). The potential for adverse impacts to groundwater is recognised as a key environmental risk for UCG projects (Waters and Milne, 2018; Camp and White 2015).

The crucial aspect of an environmentally safe UCG operation is to ensure that the potential contaminants in gas and water produced by UCG processes are contained within the in-situ gasification chamber and its close confinement zone by managing pressures in the gasification chamber so that the pressure gradients are inward, or by selecting the sites where there is no path or permeability for produced gas to escape (Camp and White, 2015; Burton et al., 2013). Another important aspect of ensuring an environmentally safe UCG is to undertake a clean shutdown and decommissioning procedure, which can remove as much of the chemical inventory as possible, instead of leaving them in the underground system (Waters and Milne, 2018; Mallett, 2017; Camp and White, 2015). Historical experience with UCG indicates a small number of cases where serious groundwater contamination has occurred, and many cases with little environmental impacts (Waters and Milne, 2018; Mallett, 2017; Camp and White, 2015; Burton et al., 2013). Field trials and demonstrations from the USA have provided reasonable evidence that the inventory of contaminants left underground were successfully reduced in the gasification chamber immediately after the operations (Waters and Milne, 2018; Camp, 2017; Camp and White 2015; Moran et al., 2013). The recent Bloodwood Creek project demonstrated that 91% of chemicals of interest left in the underground gasification chamber were removed by clean shutdown and decommissioning practices (Perkins, 2018; Mallett, 2017).

In recent years, life cycle assessment (LCA) for fossil fuel power generation with or without CCS has been widely used as a reliable method to assess the environmental performance of the systems studied (Troy et al., 2016; Koiwanit et al., 2014; Nie et al. 2014, 2013, 2011; Korre et al., 2012; James et al., 2010a, b; Koornneef et al., 2008). However, only a few publications reported on the LCA of UCG processes. Burchart-Korol et al. (2016) conducted a full LCA on heat production from UCG using life cycle inventory (LCI) data obtained from large scale laboratory reactor experiments (Stańczyk, 2015) simulating the subsurface gasification processes, while emissions, energy consumption and other LCI data for surface syngas processing and combustion processes were based on the literature. They have demonstrated that UCG with heat production had slightly better environmental performance than a surface coal plant with heat production. Hyder et al. (2016) compared life cycle GHG emissions of UCG with combined cycle gas turbine power generation with surface coal power generation options including pulverised coal (PC) fired power plants, supercritical coal (SCPC) fired plants and integrated gasification combined cycle (IGCC) plants. The analysis concluded that UCG was comparable to these technologies and that, the GHG emissions from UCG are considerably lower than the surface coal power plant options. Verma and Kumar (2015) investigated LCA of hydrogen production from UCG with or without CCS. Process engineering models were developed in Aspen Plus® and life cycle GHG emissions and energy efficiency were analysed by considering UCG operational parameters. It was concluded that, in terms of life cycle GHG emissions, UCG based hydrogen production was comparable with surface coal gasification based hydrogen production. However, UCG based hydrogen production with CCS had lower life cycle GHG emissions than natural gas based surface steam methane reforming (SMR) with CCS, surface coal gasification based hydrogen production with CCS, and renewable alternatives. Meintjies

(2011) used the UCG process data from a BHP UCG case study (BHP, 2002) and compared UCG based power generation with conventional pulverised coal fired power generation. He concluded that UCG-IGCC technology is more sustainable than the conventional PC power plant technology. UCG with combined cycle gas turbine power generation yielded significant reductions in environmental stressors related to air, water, resource consumption and waste used in the impact assessment (Meintjies, 2011). In summary, the majority of the published literature has used specific UCG experimental or pilot project data and focused only on GHG emissions and energy efficiency. UCG operational parameters and other environmental emissions, especially the potentially hazardous compounds generated during a UCG operation, have not been investigated in detail. Additionally, the life cycle performance of UCG with syngas utilisation for ammonia or methanol production have not been investigated. Nor are there any comprehensive life cycle performance comparisons between UCG based power generation options and conventional surface coal fired power generation technologies with or without CO_2 capture, transport and storage.

This paper reports on the development of UCG life cycle inventory (LCI) models, which account for coal seam quality, industrial scale panel designs and UCG process operational parameters. The data used as input to the life cycle inventory models were determined through thermo-mechanical-chemical modelling of UCG reactor operations (Andrianopoulos et al., 2016) and geomechanical assessment of field scale UCG designs operating at 6,500 kg/h (3,210 tonnes/day) coal gasified. Furthermore, LCI models for UCG site preparation, construction of surface facilities, and injection well and production well drilling have also been developed and implemented. The alternative syngas utilisation option LCI models presented here include power generation and two commercial products, ammonia and methanol. The work reported compares the life cycle carbon footprint of different conventional above ground coal fired power generation options with UCG-IGCC power generation with/without CCS for two different lignites and one bituminous coal. One of these lignites is then used to compare the life cycle performance of different syngas utilisation options for power generation and the production of ammonia and methanol with associated power generation for the same underground UCG resource exploitation scenario. The LCA models for the conventional coal utilisation options for power generation were previously developed and reported in Korre et al. (2010), Nie et al. (2011) and Nie et al. (2013).

2. Methodology

Life cycle assessment is an objective process used to evaluate the environmental burdens associated with a product, process, or activity by identifying energy and materials used and wastes released to the environment, and evaluate and implement opportunities to affect environmental improvements. As such, it is an excellent tool, which can be used to assess environmental performance and support decision-making in the whole value chain starting from raw materials extraction to processing, component fabrication, assembly, delivery, use, recycling and disposal. Its implementation is based on a series of ISO 14040 standards documented in the corresponding reference publications for practitioners: BS EN ISO 14040 (2006), BS EN ISO 14044 (2006), PD ISO/TR 14047 (2012), DD ISO/TS 14048 (2002) and PD ISO/TR 14049 (2012).

The life cycle (environmental emissions) inventory models developed for the UCG processes and alternative syngas utilisation options with/without CCS in this research are built at unit process level. They are able to trace all important environmental emissions from UCG and across syngas utilisation options to their final release to the different environmental compartments as gaseous, liquid emissions or solid waste. The models also account for fuel, raw materials and water use. The life cycle impacts of UCG-IGCC with/without CCS have also been compared with conventional coal mining and coal fired power plant options. The coal utilisation efficiency for different power generation chains is compared both at plant level and in a life cycle perspective.

The system boundaries of the three UCG systems with alternative syngas utilisation options investigated are shown in Figure 2. The utilisation of ammonia and methanol is not included within the system boundaries, therefore, the results reported include upstream and downstream processes up to and including the CO_2 injection for storage. The system boundaries comprise an underground gasifier, syngas power generation with CO_2 capture, syngas to methanol with CO_2 capture, syngas to ammonia with CO_2 capture, CO_2 pipeline transportation, CO_2 saline aquifer storage, and the consumables production and infrastructure construction processes, including UCG site construction, power plant construction, methanol plant construction, ammonia plant construction, CO_2 pipeline construction, CO_2 injection site construction.

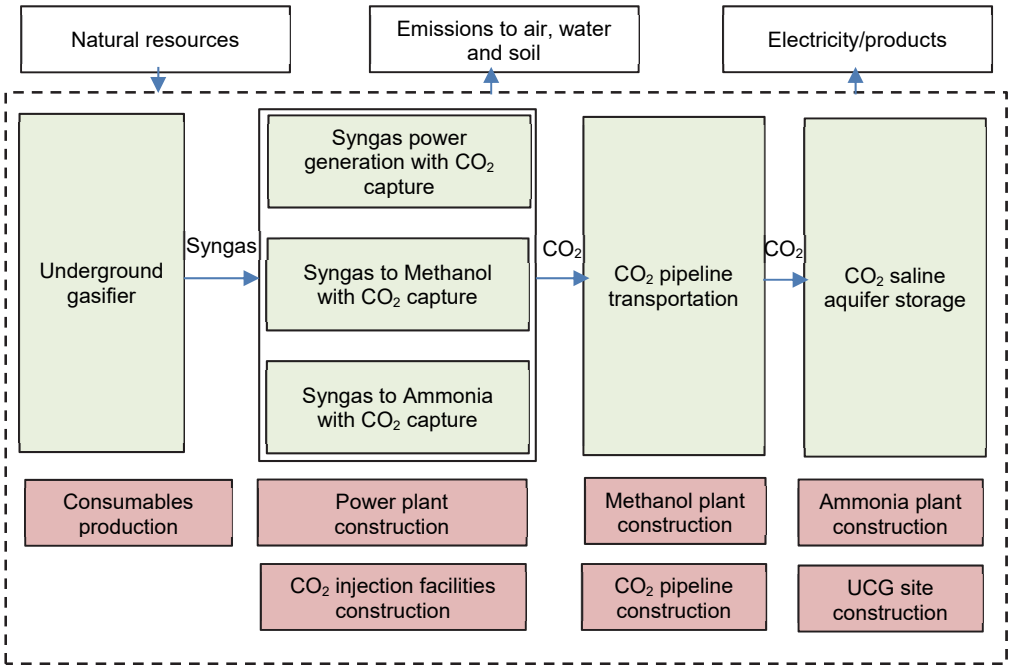


Figure 2. System boundaries used for the comparison of the three UCG systems with alternative syngas utilisation options.

Figure 3 presents the system boundaries for a comparative assessment of UCG-IGCC power generation with conventional coal utilisation options for power generation. The comparison includes UCG-IGCC power generation with/without CCS, surface Integrated Gasification Combined Cycle (IGCC) power generation with/without CCS, surface pulverised coal combustion power generation with/without CCS, and coal oxyfuel combustion power generation with/without CCS. For non UCG power generation, coal production is considered to be based on underground mining only (not opencast production) in order to ensure consistency in the comparisons made. In this case, assessment is possible with a common product, i.e. electricity, therefore, the selected functional unit reported in this work is one MWh of electricity generated. In contrast, for the comparative assessment of the three UCG systems with alternative syngas utilisation options, it is not possible to have a common functional unit based on the product of the systems as the three syngas utilisation paths lead to different products. For this purpose, the comparative assessment has been carried out based on the primary coal resource consumed, using one tonne of coal consumed as reference unit.

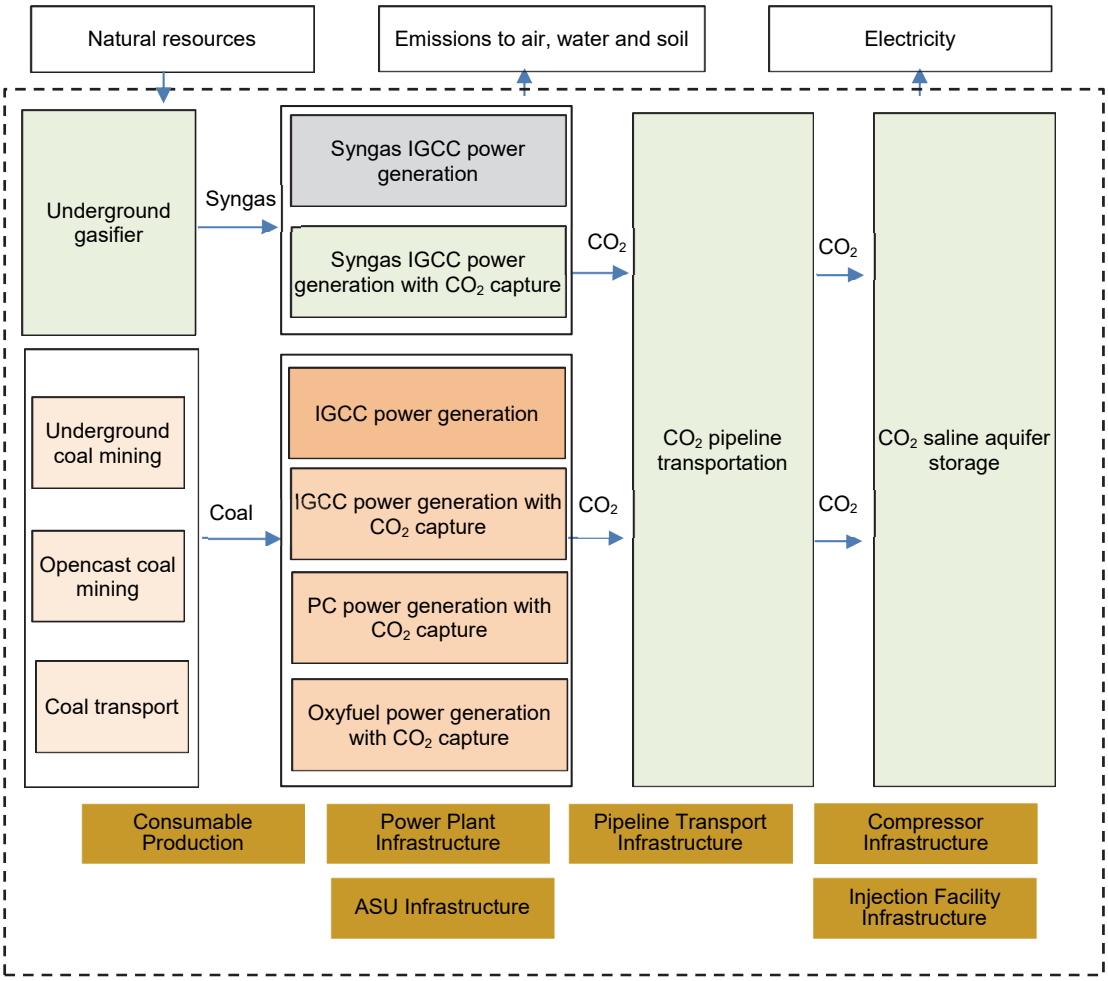


Figure 3. System boundaries used in the comparative assessment of UCG combined cycle gas turbine power generation with conventional coal utilisation options for power generation.

The life cycle inventory analysis involved data collection and the implementation of the model to quantify relevant inputs and outputs of the individual subsystems and unit processes. The work reported here uses process simulation models developed in the Aspen Plus® software, which have been validated against experimental studies (Wiatowski, et al., 2016; Andrianopoulos, 2018).

3. Life cycle inventory models developed

3.1 Life cycle inventory modelling of conventional coal production and utilisation in power generation

In order to compare the performance of UCG syngas utilisation in power generation with CO_2 capture, transport and injection for storage against other conventional coal production and utilisation options for power generation with CCS, three well researched alternatives were considered. These are pulverised coal power plant with post-combustion capture, transport and injection (Figure 4); the oxyfuel combustion, capture, transport and injection (Figure 5). Comparisons were also performed between UCG syngas utilisation in power generation and conventional Integrated Gasification Combined Cycle technology options. IGCC involves pre-combustion CO_2 capture and, in a sense, it is quite similar to UCG, as an above ground coal to syngas conversion technology. It essentially uses a high-pressure gasifier to turn coal and other carbon based fuels into pressurised syngas, followed by the removal of impurities from the syngas prior to the power generation cycle. The life cycle performance of above ground power generation plants has been reviewed and compared with the life cycle performance of the UGC process and syngas utilisation in power generation in terms of plant energy efficiency and GHG footprint.

Imperial College's in-house LCA models, as previously reported in Korre et al. (2010), Nie et al. (2011) and Nie et al. (2013), have been used for this purpose. These models are developed at unit process level and employ

engineering calculations or process simulation approaches to quantify all the inputs and outputs, tracking emissions and energy consumption at unit process level, sub-system level and for the whole system.

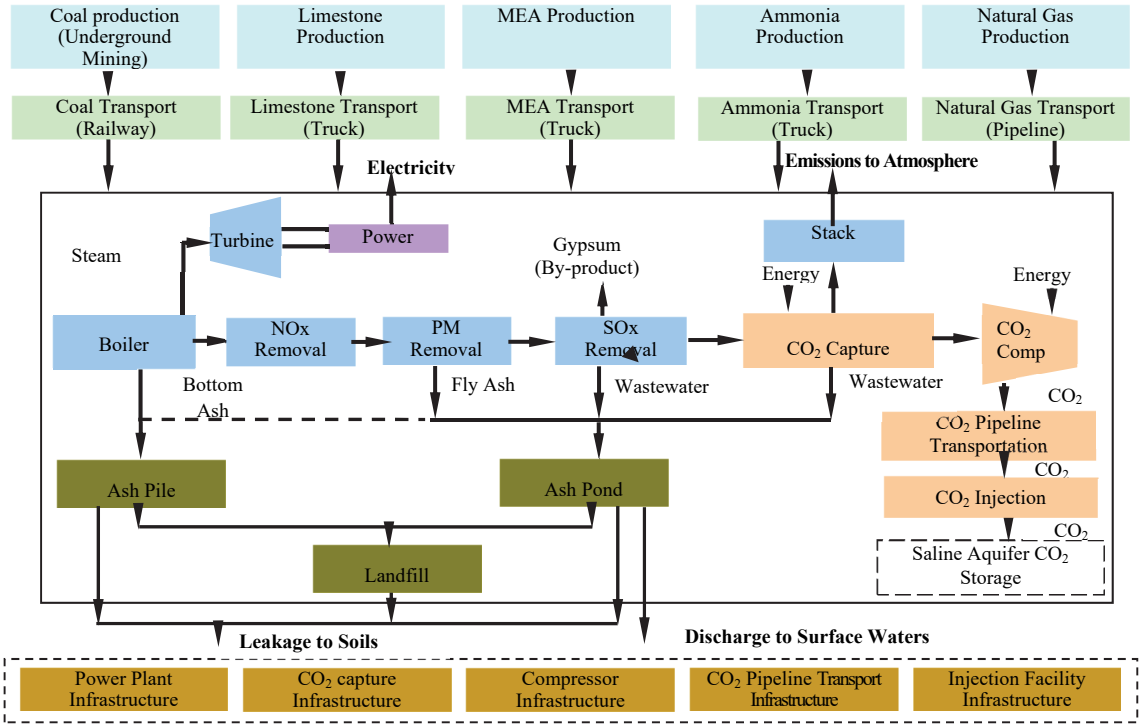


Figure 4. The component LCI models of the pulverised coal power plant with post-combustion capture, transport and injection.

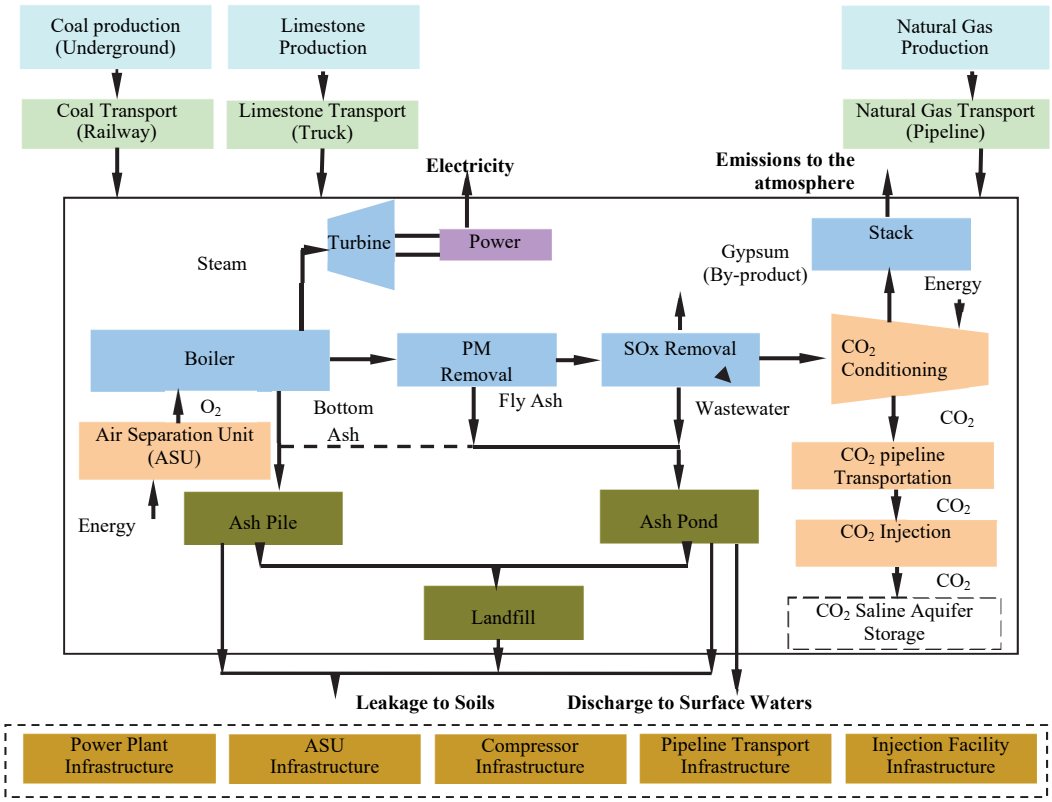


Figure 5. The component LCI models of the pulverised coal power plant with oxyfuel combustion, capture, transport and injection.

3.2 Life cycle inventory modelling of UCG with alternative syngas utilisation options

In order to ensure high-accuracy in the Life Cycle Inventory (LCI) models developed, the process simulation software Aspen Plus® was used to generate the LCI data for the three UCG syngas utilisation options: UCG-IGCC power generation with CO_2 capture, UCG ammonia production with CO_2 capture and associated power, and UCG methanol production with CO_2 capture and associated power. In order to conduct the analysis, the UCG process with relevant syngas utilisation systems were broken into sub-systems and were modelled at unit process level. For consistency, the same CO_2 injection process was modelled for all syngas utilisation options.

Gas composition, operational parameters (pressure, temperature), physical properties of process flows, and chemical emissions were all considered in the LCI models at unit process level. The use of Aspen Plus® software allowed to simulate accurately the intermediate flows and emissions, and screen the potential environmental impacts of UCG with different syngas utilisation options. The flows and emissions considered for all the LCI models are listed in Table 1. Since the three systems analysed all have liquid and waste treatment units and incinerators, liquid emissions were considered as treated and converted to air emissions for the impact assessment. The conceptual designs for the UCG-IGCC power generation plant, the UCG ammonia plant with associated power, and the UCG methanol plant with associated power, including CO_2 capture, are illustrated in Figures 6, 7 and 8 respectively.

An oxygen enriched air fed underground coal gasification panel, which delivers a low calorific value raw gas at a thermal output of 20 – 25 MWt per gasifier is used as the source for the syngas. The coal consumption rate per each standard gasifier in the industrial scale field example is taken as 6,500 kg/h. Hot production well gas at ~350 °C is quenched with recycled grey water and produces large volumetric quantities of low concentration gas liquor (< 5% hydrocarbon and ash load). The gas liquor requires substantial treatment, e.g. biological digestion or incineration followed by digestion of the scrubber liquor. The quench is followed by a sour shift reactor to shift CO to H_2 through the water gas shift reaction. The sour shift is positioned upstream of acid gas removal so that the produced CO_2 from the sour shift reactor reports to the acid gas removal unit. The extent of the sour shift reactor depends on the degree of pre- and post- carbon capture desired, as well as maintaining a steady gas composition to the gas turbine system. The CO concentration for ammonia synthesis is typically limited to below 200 ppm as it deactivates the catalyst. In the case of methanol plant, the shift reaction is controlled to yield approximately 2 for the ratio $(H_2\text{-}CO_2)/(CO+CO_2)$. The extent of the sour shift reaction is set to zero for the UCG-IGCC scenario used.

Table 1. List of intermediate flows and emissions considered in the LCI models.

Chemical compounds traced as inputs/outputs to unit processes					
CO	C_2H_6	$C_{12}H_{24}$	$C_{24}H_{50}$	STYRENE	TAR3
CO_2	C_3H_6	$C_{13}H_{28}$	$C_{25}H_{52}$	INDENE	TAR4
H_2	C_3H_8	$C_{13}H_{26}$	$C_{26}H_{54}$	BENZTHIO	TAR5
H_2O	C_4H_8	$C_{14}H_{30}$	$C_{27}H_{56}$	ANILINE	TAR6
N_2	C_4H_{10}	$C_{14}H_{28}$	$C_{28}H_{58}$	NAFTALEN	TAR7
O_2	C_5H_{10}	$C_{15}H_{32}$	$C_{29}H_{60}$	MNAFTALE	TAR8
Ar	C_5H_{12}	$C_{15}H_{30}$	$C_{30}H_{62}$	ANTRACEN	TAR9
C	C_6H_{12}	$C_{16}H_{34}$	CYCLOPEN	PHNAFTAL	TAR10
HCl	C_6H_{14}	$C_{16}H_{32}$	CYCLOHEX	DECNAFTH	TAR11
Cl_2	C_7H_{14}	$C_{17}H_{36}$	CYCLOHEP	PHENANTH	TAR12
NH_3	C_7H_{16}	$C_{17}H_{34}$	BENZENE	BENZANTH	TAR13
NO_2	C_8H_{16}	$C_{18}H_{38}$	TOLUENE	PYRENE	TAR14
HCN	C_8H_{18}	$C_{18}H_{36}$	MPXYLENE	ACRIDINE	TAR15
H_2S	C_9H_{18}	$C_{19}H_{40}$	PHENOL	ANTHRAQU	TAR16
SO_2	C_9H_{20}	$C_{19}H_{38}$	EMBENZEN	NITRDIPH	TAR17
SO_3	$C_{10}H_{22}$	$C_{20}H_{42}$	CRESOL	METHANOL	TAR18
COS	$C_{10}H_{20}$	$C_{20}H_{40}$	XYLENOL	MEK	
S	$C_{11}H_{24}$	$C_{21}H_{44}$	MESITYL	ACETONE	
CH_4	$C_{11}H_{22}$	$C_{22}H_{46}$	PYRIDINE	TAR1	
C_2H_4	$C_{12}H_{26}$	$C_{23}H48$	METPYRID	TAR2	

The acid gas removal system achieves deep sulphur and carbon removal as required for commercial catalysts for chemical synthesis. A Selexol acid gas removal system is used in all three processes. The Selexol solvent dissolves the acid gases from the feed gas at relatively high pressure, usually 300 to 2,000 psi (2.07 to 13.8

MPa). The rich solvent containing the acid gases is then let down in pressure and/or steam stripped to release and recover the acid gases.

The remaining CO is converted to methane in a methanation reactor to achieve the CO feed concentration for ammonia synthesis. The methanation reaction produces H_2O that is removed through cooling of the synthesis gas as is required for the ammonia synthesis catalysts. Both the ammonia and methanol synthesis systems include the typical large gas recycle due to the low per pass conversion rates. The high concentration of nitrogen in the synthesis gas necessitates a high purge rate from the synthesis loop to minimise the accumulation of inert components. The high nitrogen concentration in the UCG synthesis gas produces a H_2:N_2 ratio of ~1.1. Due to the relatively high and variable concentration of the CH_4 in the synthesis gas, and for simplicity in the downstream UCG processes, it was decided that the purge gas from the synthesis loop and the purge from the ammonia and methanol distillation columns will report to an open cycle gas turbine system rather than a hydrogen recovery system.

The power generation system includes a gas turbine with a heat recovery steam generator (HRSG). The high nitrogen concentration in the synthesis gas reduces the output from the gas turbine system due to the high work requirement to compress the air feed to the combustor of the gas turbine.

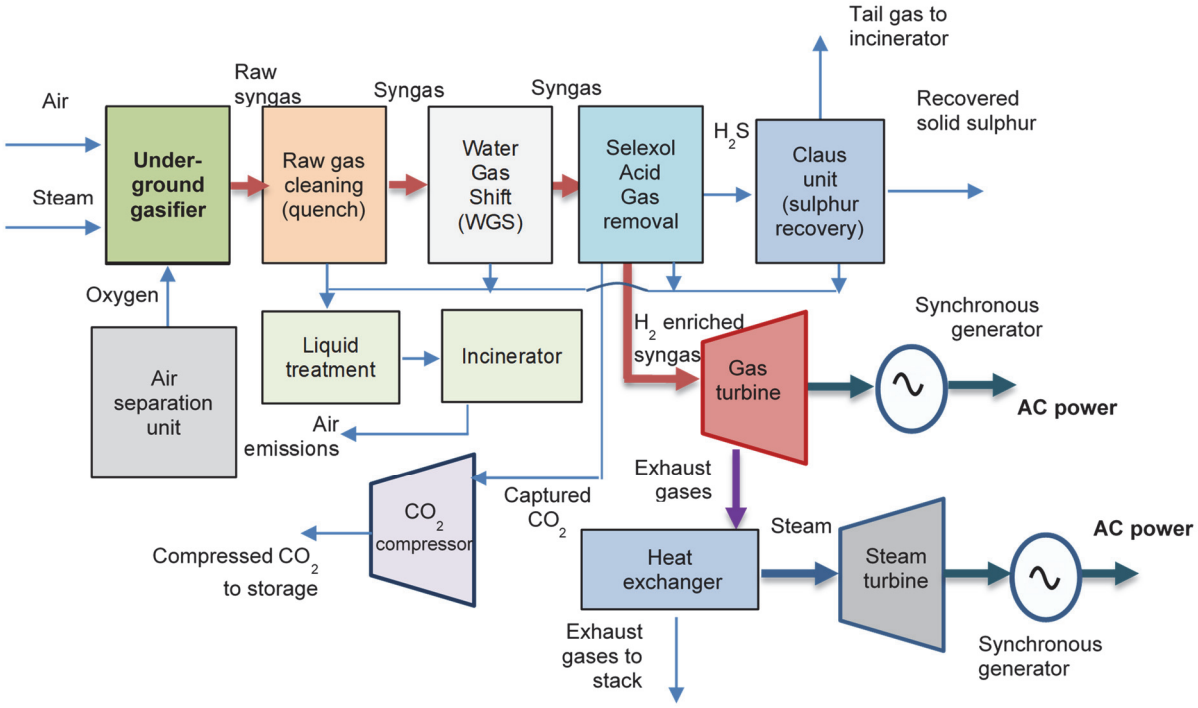


Figure 6. Process flow diagram for the UCG-IGCC power generation with CO_2 capture.

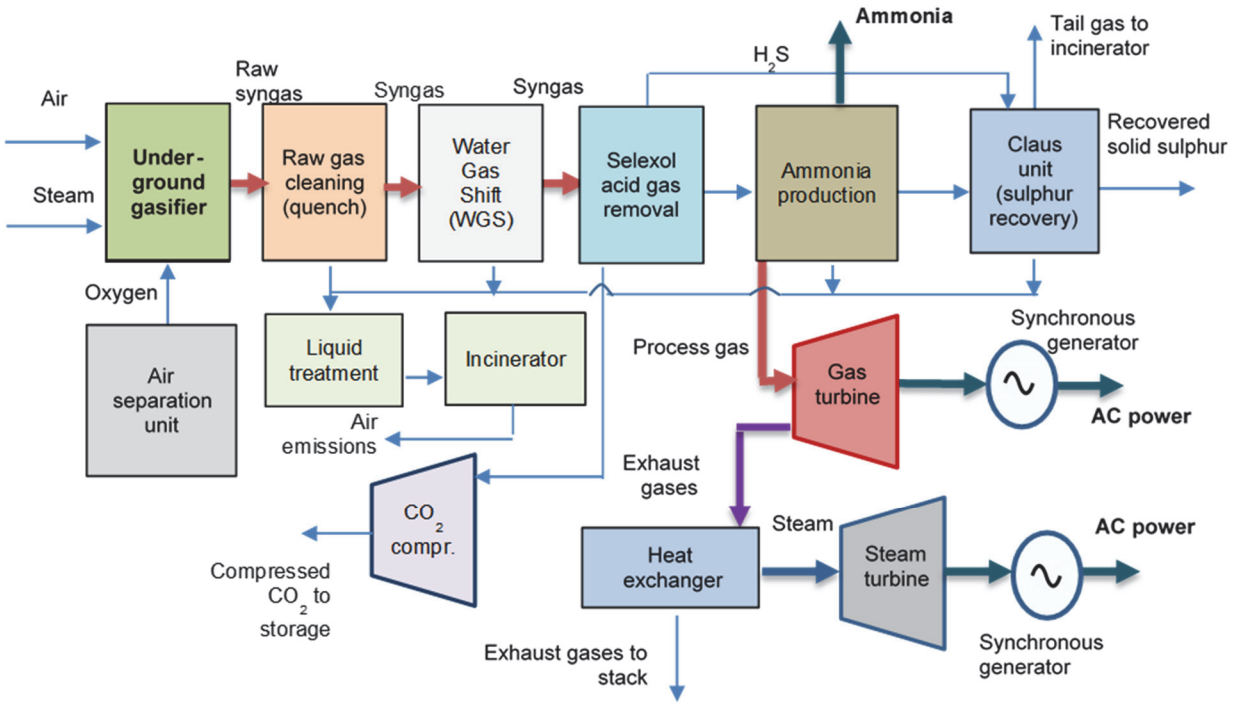


Figure 7. Process flow diagram for the UCG ammonia production with CO_2 capture and associated power generation.

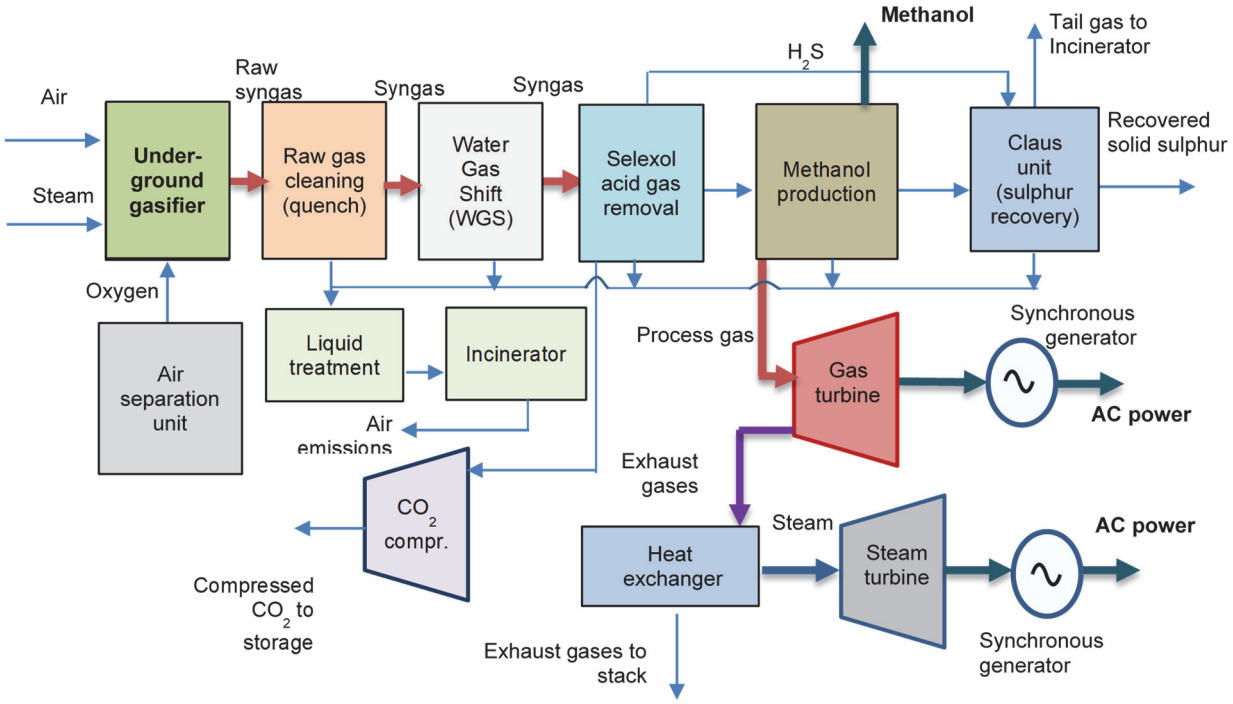


Figure 8. Process flow diagram for the UCG methanol production with CO_2 capture and associated power generation.

3.3 Example unit process models constructed

The detailed process engineering models developed in Aspen Plus® software for each unit process considered in different UCG syngas utilisation options indicate the high level of sophistication implemented in the LCI modelling carried out. Figures 9 and 10 illustrate the details of the UCG reactor and the fully integrated gasification, syngas processing and liquid and waste treatment LCI models developed respectively. Table 2 presents an example parameterisation dataset used in the underground gasification process LCI model.

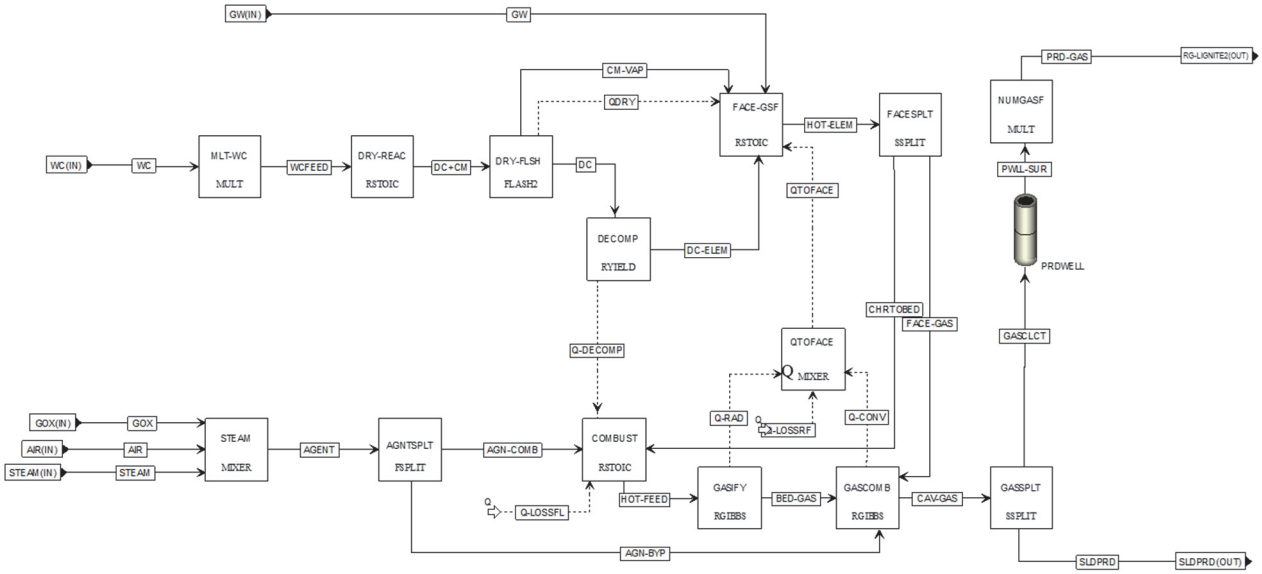


Figure 9. Underground coal gasifier LCI model developed in Aspen Plus®.

Table 2. Example parameterisation dataset used in the underground gasification process LCI model.

Variable	Value
Thermal output	20 – 25 MW_t
Instantaneous coal consumption	6,500 kg/h
Gasification agent:	O_2 enriched air at 35 % wt. dry basis (before steam addition, if required.)
Operating pressure	2,000 kPa gauge mode
Ground water influx	5 $kg.m^{-2}.h^{-1}$
Affected cavity extent	750 m^3 or 1,000 tonnes coal consumed
Gasifier roof surface area	150 m^2
Gasifier side wall surface area	100 m^2
Exposed coal surface area	175 m^2 (exposed overburden decreases active cavity extent)

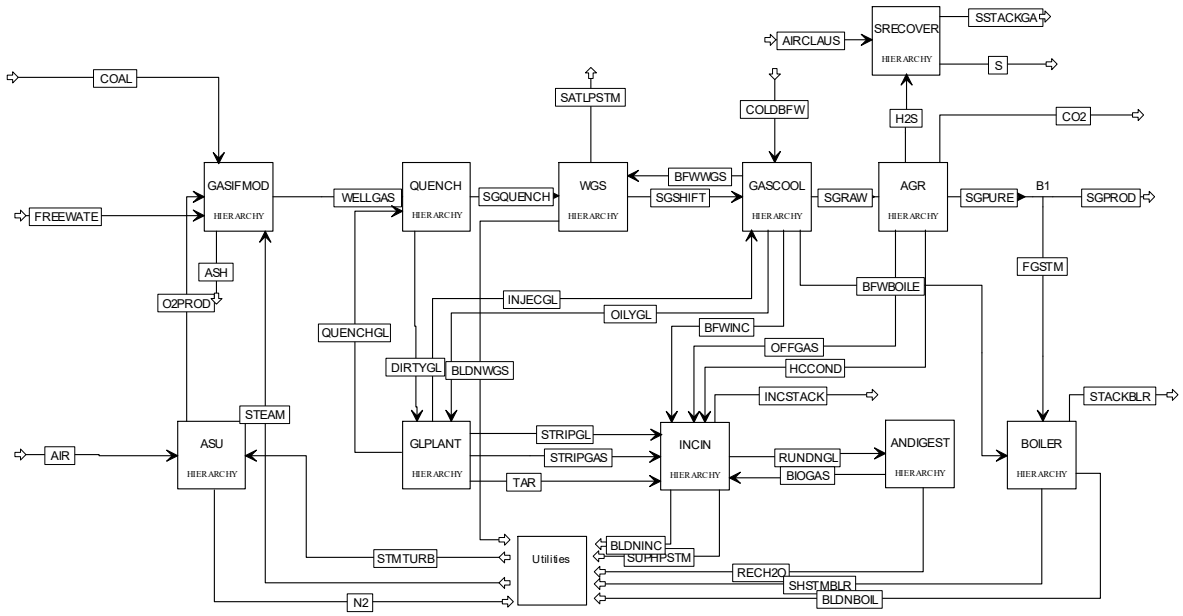


Figure 10. An overview of the fully integrated gasification, syngas processing and liquid and waste treatment LCI models developed in Aspen Plus®.

Table 3. Key properties of the three coals used in the study.

	Bituminous coal	Lignite 1	Lignite 2
Proximate analysis			
Moisture (wt.% air dried)	2.89	11.13	11.60
Fixed carbon (wt.% dry)	67.07	29.80	44.00
Volatile matter (wt.% dry)	30.50	63.90	39.20
Ash (wt.% dry)	2.43	6.30	16.80
Ultimate analysis			
Ash (wt.% dry)	2.43	6.19	16.80
Carbon (wt.% dry)	83.26	55.90	59.60
Hydrogen (wt.% dry)	4.65	5.25	3.80
Nitrogen (wt.% dry)	1.16	0.72	0.72
Sulphur (wt.% dry)	0.21	0.74	0.28
Oxygen (wt.% dry)	8.29	31.20	18.80
Sulphur analysis			
Pyritic (wt.% dry)	0.06	0.35	0.09
Sulphate (wt.% dry)	0.04	0.03	0.06
Organic (wt.% dry)	0.11	0.36	0.13
Heating value			
LHV (MJ/kg)	32.40	19.73	16.17

4. The UCG life cycle inventory model results for the three different coal types considered

The LCI model developed for the UCG process has been implemented for three different coal types, which included two lignites and one bituminous coal. The key properties of the three coals used are listed in Table 3. In terms of upstream GHG emissions due to underground coal mining, processing, transport and pulverisation before they are fed to a conventional surface power generation plant, the two lignites chosen represent the two extremes with respect to their in situ gas contents and specific emission rates during coal production. Lignite 1 is representative of a relatively high methane content/specific emission coal, whereas Lignite 2 is representative of a relatively low methane content/specific emission coal. Nevertheless, both lignites have relatively lower methane content/specific emission characteristics when compared to the bituminous coal used, which has the methane emission characteristics of a typical hard coal from European coalfields. The results of LCI analyses in terms of syngas quality and properties are presented in Table 4.

Cold gas efficiency reported in Table 4 is defined as lower heating value of produced raw syngas divided by lower heating value of coal gasified. For the bituminous coal used, the $O_2/Coal_{daf}$ ratio has been adjusted to 1.00. According to the literature, surface IGCC plants yield a cold gas efficiency that ranges from 70 to 90%. The underground coal gasification model results in Table 4 show that UCG has a lower cold gas efficiency, as UCG designs are restricted by geological and operational conditions. This implies that less energy is transferred to the syngas generated. In surface IGCC plants, on the other hand, optimised operational conditions can lead to higher cold gas efficiencies.

Table 4. Underground gasifier life cycle inventory model results for the Bituminous coal, Lignite 1 and Lignite 2.

	Bituminous coal	Lignite 1	Lignite 2
Heating value of product gas (MJ/Nm^3)	5.29	4.55	5.51
Cold gas efficiency (%)	60.17	61.59	81.95
Thermal energy in product gas (MW)	35.20	21.94	24.20
Radiation heat from bed into coal (kW)	2,811.70	1,882.40	1,881.80
Convection heat from cavity gas to coal (kW)	378.60	722.40	516.80
Heat loss into overburden (kW)	1,709.10	996.30	1,084.70
Heat loss into underburden (kW)	1,139.40	664.20	723.10
Ratio $O_2/Coal_{daf}$	1.00	0.75	0.72
Ratio $H_2O/Coal_{daf}$	0.23	0.34	0.35

Table 5 presents the energy efficiency data for the UCG-IGCC plant without CO_2 capture and compression for the three coal types. Plant energy efficiency is defined as electricity generated from the plant divided by the heating value of coal used/gasified. The energy efficiency of the combined cycle gas turbine is set at 57%, which is comparable to the literature values (Fout et al., 2015). The plant energy efficiency reported here also

considers the energy consumed by air separation unit (ASU), oxygen compression, air compression, and acid gas removal (AGR) as energy penalties. The ASU and AGR models developed are modified from the literature (Field and Brasington, 2011). In the case of a plant without CO_2 capture, the AGR unit mainly removes H_2S and only a small amount of CO_2 is removed by the AGR. Therefore, the energy consumption of the AGR is smaller. In addition, there is no water gas shift (WGS) reaction unit.

Table 6 presents the plant energy efficiency data for the UCG-IGCC plant with CO_2 capture and compression for the three coal types. This time, a water gas shift reaction unit is included and the energy released from WGS is recovered by HRSG. The AGR unit consumes considerable energy as it removes H_2S and CO_2. The CO_2 compression unit also requires considerable energy. Table 5 and Table 7 demonstrate that the UCG-IGCC plant energy efficiency is determined by the underground gasifier efficiency. Lignite 1 and Lignite 2 are shown to have a better plant energy efficiency than the bituminous coal.

Table 5. Energy efficiency data for the UCG-IGCC plant without CO_2 capture.

	Bituminous coal	**Lignite 1**	**Lignite 2**
Heating value of consumed coal from 20 panels (MW)	1170.00	712.47	583.92
Energy used for oxygen production (MW)	-13.57	-11.61	-10.68
Energy used for oxygen and nitrogen compression (MW)	-13.53	-11.58	-10.66
Energy used for air compression (MW)	-36.42	-18.48	-18.06
Energy used for AGR (MW)	-1.29	-0.96	-0.96
Electricity generated from gas turbine (MW)	253.43	157.98	174.24
Electricity generated from steam turbine (MW)	154.88	96.55	96.80
Net electricity output (MW)	343.49	211.91	230.68
Plant efficiency (%)	29.36	29.74	39.51

Table 6 Energy efficiency data for the UCG-IGCC plant with CO_2 capture and compression.

	Bituminous coal	**Lignite 1**	**Lignite 2**
Heating value of consumed coal from 20 panels (MW)	1170.00	712.47	583.92
Energy used for oxygen production (MW)	-13.57	-11.61	-10.68
Energy used for oxygen and nitrogen compression (MW)	-20.30	-17.37	-15.98
Energy used for air compression (MW)	-36.42	-18.48	-18.06
Energy recovered from WGS unit (MW)	1.52	3.69	5.86
Energy used for CO_2 compression (MW)	-18.28	-13.53	-13.53
Energy used by AGR (MW)	-12.94	-9.58	-9.58
Electricity generated from gas turbine (MW)	253.43	157.98	164.76
Electricity generated from steam turbine (MW)	154.88	96.55	91.54
Net plant electricity output (MW)	308.31	187.64	194.31
Plant efficiency (%)	26.35	26.34	33.28

Table 7 presents the syngas, flue gas and CO_2 stream composition after key unit processes for a UCG plant without and with CO_2 capture utilising each of the three coals considered and modelled in the Aspen Plus® software.

368 **Table 7.** Stage-by-stage syngas, flue gas and CO_2 stream composition at the exit of individual processes for a UCG plant without and with CO_2 capture for the three coals considered
369 (unit: kg/hr).

	Bituminous coal UCG plant without CO_2 capture				**Lignite 1 UCG plant without CO_2 capture**				**Lignite 2 UCG plant without CO_2 capture**			
	Syngas out of UCG gasifier	after quench and WGS	after AGR	Flue gas out of stack	Syngas out of UCG gasifier	after quench and WGS	after AGR	Flue gas out of stack	Syngas out of UCG gasifier	after quench and WGS	after AGR	Flue gas out of stack
H_2	2,267.33	2,267.33	2,264.04	0.23	3,483.30	3,483.30	3,478.23	0.05	4,380.77	4,380.77	4,374.40	0.27
CO	76,008.16	75,932.44	74,713.30	20.29	94,472.71	94,308.36	92,259.55	5.24	109,127	108,911	107,123	28.86
CO_2	216,368	216,083	167,599	327,481	78,148.61	78,067.59	47,134.08	201,205	68,835.68	68,743.04	47,070.36	225,259
CH_4	17,248.32	17,144.08	15,301.41		3,696.86	3,660.56	3,158.27		3,920.71	3,875.57	3,450.29	
N_2	269,881	269,653	224,219	999,248	150,218	149,992	124,171	888,021	145,436	145,189.00	117,624	880,846
O_2				92,074.35				140,209				122,736
H_2O	194.57	51,255.47	193.37	76,509.34	53,955.88	70,661.50	214.37	38,391.72	31,141.79	49,950.54	14.59	46,857.75
H_2S	281.78	224.80			904.09	423.77			342	168.64	0.00	
NH_3	31,618.56	2,9073.75	13,641.35		4.82	4.05	0.48		17.95	14.63	2.46	
NO_2				25.01				36.34				37.82
NO				2,639.92	0.01	0.01	0.01	2,547.72				3,892.90
S					0.05							
SO_2					8.51	7.62	3.30	3.23	0.01	0.01	0.01	0.01
CH_3OH	1,604.11	1,381.50	66.14									

	Bituminous coal UCG-IGCC with CCS					**Lignite 1 UCG-IGCC with CCS**					**Lignite 2 UCG-IGCC with CCS**				
	Syngas out of UCG gasifier	after quench and WGS	after AGR	Flue gas out of stack	CO_2 captured	Syngas out of UCG gasifier	after quench and WGS	after AGR	Flue gas out of stack	CO_2 captured	Syngas out of UCG gasifier	after quench and WGS	after AGR	Flue gas out of stack	CO_2 captured
H_2	2,181.61	7,583.46	7,572.44	3.04	11.02	3,486.85	10,202.70	10,187.87	0.14	14.83	4,386.80	12,140.64	12,122.99	0.63	17.64
CO	75,892.08	758.16	751.84	33.06	4.63	94,422.85	942.59	931.29	0.57	5.73	109,043	1,088.27	1,081.58	2.93	6.65
CO_2	216,410	334,053	16,712.14	62,616.53	299,066	78,226.95	224,764	10,051	21,153.53	179,864	68,968.26	238,154	12,373.9	24,603.51	225,180
CH_4	17,248.32	17,143.64	16,032.3		878.22	3,696.86	3,660.56	3,347.35		183.36	3,920.71	3,875.57	3,673.47		201.23
N_2	269,535	269,306	219,540	1,002,420	6,119.21	150,218	149,992	121,931	885,774	3,398.57	145,436	145,189	121,651	884,936	210.98
O_2				72,977.32					138,358					120,949	
H_2O	177.46	12,653.23	10.94	142,491	163.26	53,924.05	32,535.67	13.4	98,577.75	200	31,087.52	667.92	230.73	116,838	0.66
H_2S	281.78	224.69			0.04	904.23	423.9			0.08	342	168.69			0.03
NH_3	32,039.58	29,454.44	24,296.66			4.85	4.08	1.23			18.18	14.81	14.61		
NO_2				26.06					36.38					37.28	
NO				4,594.95		0.01	0.01	0.01	2,562.74					3,781.18	
S						0.05									
SO_2						8.27	7.40	4.99	4.88		0.01	0.01	0.01	0.01	
CH_3OH	1,706.48	1,467.92	244.99												

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4.1 Life cycle energy efficiency analysis of coal to electricity: UCG-IGCC power plant with/without CO_2 capture vs surface power generation with/without CO_2 capture

Figure 11 presents the comparison of plant energy efficiency of a UCG-IGCC power plant with/without CO_2 capture with that of surface power generation with/without CO_2 capture cases reported by the International Energy Agency (Deborah and John, 2007) and the US Department of Energy (Fout et al., 2015). It is shown that, at plant level, surface plants with/without CO_2 capture generally have higher energy efficiencies than the UCG power plants. Energy efficiency of UCG plants have considerable variation due to different types of coal used.

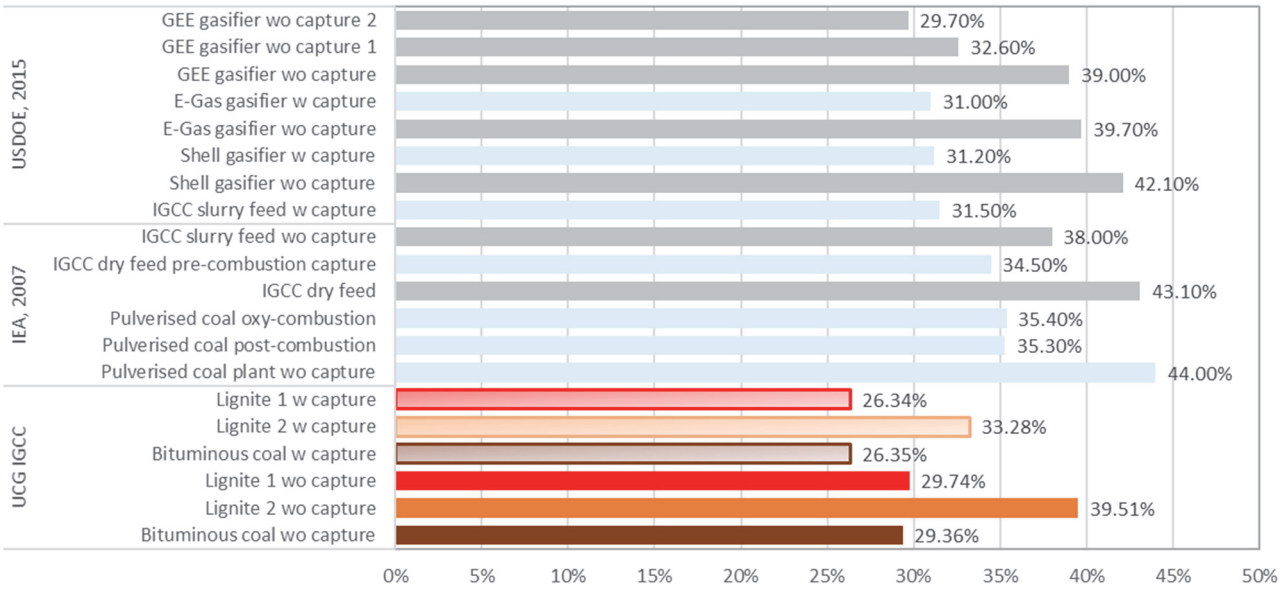


Figure 11. Energy efficiency comparison of UCG-IGCC power generation with different surface power plant options.

As UCG-IGCC power generation does not require coal mining, preparation and transportation, the corresponding GHG emissions are avoided. However, for conventional surface coal power plant options, the life cycle impacts from coal mining, preparation and transportation need to be added, therefore, further reducing the overall coal to electricity efficiency. Assuming that an underground coal mine is linked to a power plant with a 300 km railway, then the energy requirement will be 158.92 kW equivalent electricity per tonne of coal delivered to the plant, as estimated using Imperial College's in-house ICLCA model (Korre et al., 2010; Nie et al., 2011, 2013). This suggests that, for a power plant with plant energy efficiency of 40%, around 5.18 % of the electricity generated is consumed for coal mining, preparation and transport. As Figure 11 illustrates, a UCG-IGCC power plant with/without CO_2 capture for Lignite 2 has a better plant energy efficiency than some of the surface plants with/without CO_2 capture. However, this is not the case for Lignite 1 and the bituminous coal, suggesting that for some coal types or coal seam conditions with low methane content or emission characteristics, UCG-IGCC power generation can have a better energy efficiency than that of surface plants.

4.2 Life cycle GHG analysis of coal to electricity: UCG-IGCC power plants with/without CCS vs surface coal power plants with/without CCS

Imperial College's in house LCA model was used to generate the life cycle GHG emissions for UCG-IGCC, pulverised coal post-combustion and oxyfuel combustion CO_2 capture and storage alternatives (Figure 12). Direct emissions from underground coal mining, GHG emissions from coal mining power consumption, coal preparation and transportation were also accounted for. Figure 12 demonstrates that lignite UCG-IGCC power plants without CCS have a smaller life cycle carbon footprint than that of underground mined lignite fired post-combustion power plants without CCS. Comparison of the results obtained for the three different coals have shown that the life cycle carbon footprint of conventional coal fired power generation is very much dependent on the in-situ methane content of the coal used, and methane emissions experienced during mining and the accompanying upstream processes, whereas the same for UCG-IGCC power depends more on the UCG process dependent syngas composition. Therefore, the UCG-IGCC plant utilising a relatively low methane content Lignite 2 yielded a larger life cycle carbon footprint than that of underground mined Lignite 2 fired post-combustion and oxyfuel combustion capture power plants. On the other hand, bituminous coal

UCG-IGCC power plants with/without CCS have shown a greater life cycle carbon footprint than that of lignite UCG-IGCC and conventional surface power plants with/without CCS. Table 8 compares the electricity generation, CO_2 capture and CO_2 emissions data for the two lignites and the bituminous coal.

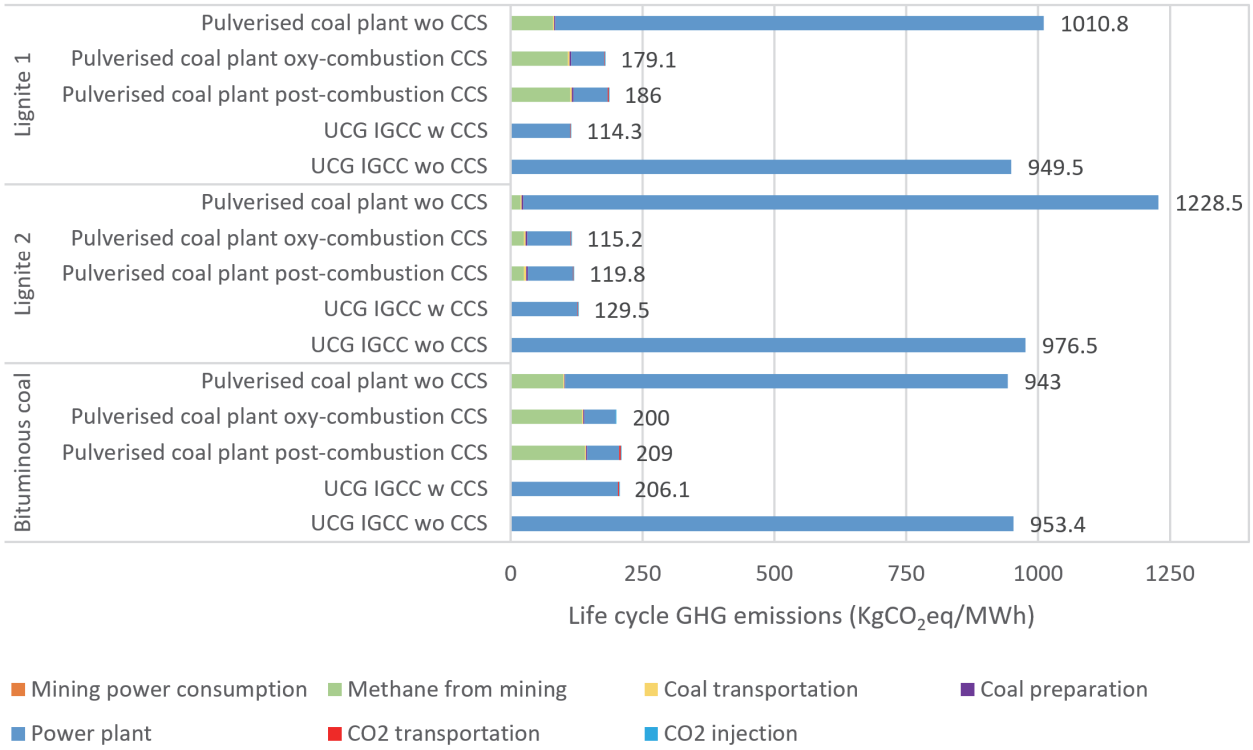


Figure 12. Life cycle GHG footprint of electricity for two lignites and one bituminous coal (kg CO_2-eq/MWh).

Table 8 UCG-IGCC power generation with CO_2 capture for different coals (Plant level).

	Bituminous coal	**Lignite 1**	**Lignite 2**
Electricity generated (MWh)	308.31	187.64	194.31
CO_2 captured (kg/hr)	299,066	179,864	225,180
CO_2 emitted to the atmosphere (kg/hr)	62,617	21,154	24,603
CO_2 captured (kg/MWh)	970.02	959.56	1,158.87
CO_2 emitted to the atmosphere (kg/MWh)	203.1	112.73	127.6

The life cycle impact assessment carried out covers emissions related to the Abiotic Depletion Potential (ADP), Acidification Potential (AP), Eutrophication Potential (EP), Freshwater Aquatic Ecotoxicity Potential (FAEP), Global Warming Potential (GWP), Human Toxicity Potential (HTP), Marine Aquatic Ecotoxicity Potential (MAEP), Photochemical Ozone Creation Potential (POCP), Ozone Depletion Potential (ODP) and Terrestrial Ecotoxicity Potential (TETP). The commercial software GaBi v6 (Thinkstep GaBi, 2016) was used to carry out the environmental impacts analysis using the impact indicator system of CML2011-Jan 2016 (CML, 2016). As not all emissions estimated through the detailed UCG and syngas utilisation process modelling have an environmental impact potential in CML2011-Jan 2016, only the relevant subset of parameters listed in Table 1 was selected for the LCA analysis, as listed in Table 9. The Lignite 2 characteristics listed in Table 4 have been used as common input coal resource exploited through UCG to illustrate the relative performance of the alternative power generation technologies compared.

Table 6. UCG and syngas utilisation air emissions with a life cycle impact potential (CML2011 Jan 2016).

Hydrogen sulphide	Sulphur dioxide
Particulates, < 2.5 μm	Sulphur trioxide
Phenol	Organic emissions to air (group VOC)
Inorganic emissions to air	Group NMVOC to air
Ammonia	Benzene
Carbon dioxide	Butane
Carbon monoxide	Butene
Chlorine	Ethane
Hydrogen	Ethene (ethylene)
Hydrogen chloride	Methanol
Hydrogen cyanide (prussic acid)	Propane
Nitrogen (atmospheric nitrogen)	Propene (propylene)
Nitrogen dioxide	Methane
Nitrogen monoxide	Other emissions to air
Oxygen	Carbonyl sulphide

In this study, it is assumed that the potential contaminants in gas and water produced during UCG processes are contained within the gasification chamber and its close confinement zone by careful management of the pressure in the in-situ gasification chamber. Moreover, a clean shutdown and decommissioning procedure, which can remove as much of the chemical inventory as possible, is assumed. Therefore, emissions from the subsurface gasifier to surface waters and soils are considered to be negligible. On the other hand, liquid and solid waste emissions from syngas, as well as the emissions from surface processes, which take place within the surface processing facilities, are considered and modelled.

Figure 13 shows the life cycle environmental impact comparison of UCG-IGCC power generation with CCS and two above ground power generation options with CCS (post-combustion and oxyfuel) by using Lignite 2 as the fuel. The functional unit used is one MWh electricity generated. In this analysis, upstream processes, including coal mining, processing, transportation, plant construction and consumable production for the above ground power generation options are considered. The results reveal that UCG-IGCC power generation with CCS has the highest ADP as this process has the lowest energy efficiency. The UCG-IGCC power generation with CCS has a comparable GWP to the two above ground power generation options with CCS, as significant CO_2 emissions are generated from the incinerator. Furthermore, syngas components, which are determined by underground gasification processes, carry a significant volume of CH_4, which also affect the CO_2 eq. emissions at the gas turbine. It should be noted here that UCG-IGCC power generation with CCS implements the equivalent of pre-combustion CO_2 capture at an overall capture rate of 80-90% (Table 8), while post-combustion capture of the CO_2 generated at the incinerator and stack is not considered together with the UCG-IGCC power generation with CCS. The upstream processes involved in oxyfuel and post-combustion CCS contribute significantly to AP and EP, mainly due to the Sox and NOx emissions during coal mining. The post-combustion CCS option HTP increases significantly, because the MEA production process leads to significant HTP related emissions. Oxyfuel combustion has the highest FAEP and MAEP, due to potential HF emissions to water during gas conditioning. The post-combustion plant FAEP impacts come from trace metal emissions following the solid waste treatment process. The main FAEP contributor of UCG-IGCC power generation with CCS is air emission of phenol from the incinerator, which originates from the underground gasification processes. Oxyfuel and post-combustion CCS options have considerably high TAEP due to the upstream emissions contribution. UCG-IGCC power generation with CCS has the least HTP, MAEP and TAEP impacts, because of the protective effect of the liquid and solid waste treatment units. The slight increase of POCP for the oxyfuel and post-combustion CCS options are caused by the coal mining and coal transportation processes. ODP is entirely due to emissions from upstream processes with the majority arising from coal mining. Consequently, the UCG power generation option has the lowest ODP, as it does not involve coal mining.

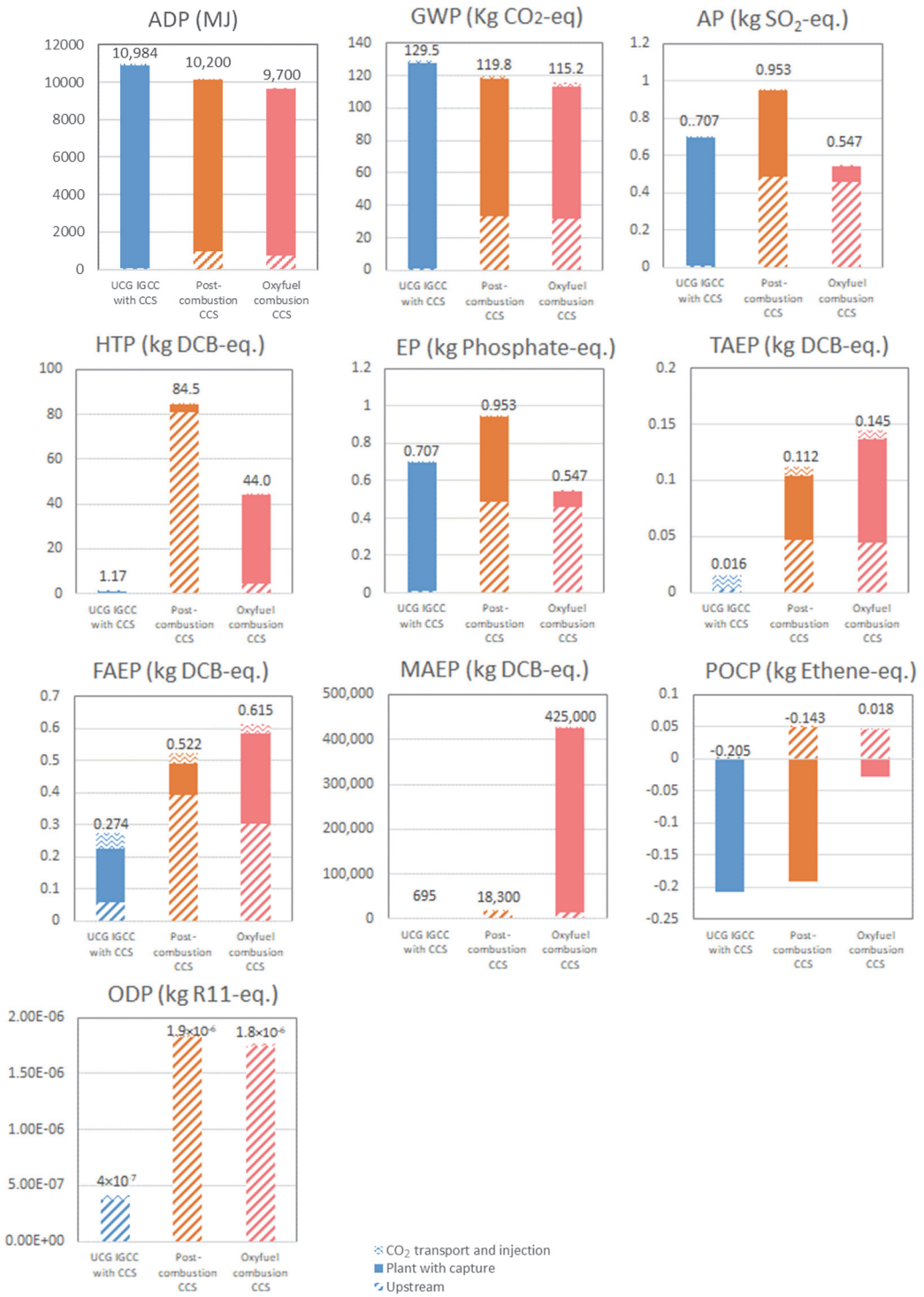


Figure 13. Comparison of life cycle environmental impacts of UCG-IGCC power generation with CCS and surface post-combustion and oxyfuel power generation with CCS using Lignite 2 (functional unit 1MWh).

5. Life cycle environmental impact analysis of UCG with alternative syngas utilisation options

Lignite 2 characteristics listed in Table 4 were used as the common input coal resource exploited through UCG to illustrate the relative performance of alternative syngas utilisation options. The reference unit used for the comparative assessment is one tonne of Lignite 2. Two separate assessments were carried out:

- a facility level analysis beginning with the UCG facility and ending at the gate of the surface plant utilising the syngas, i.e. UCG-IGCC power generation only; UCG with methanol production and associated electricity generation; and UCG with ammonia production and associated electricity generation.

- a life cycle analysis, including all resources supply, the infrastructure impacts, the operation of the three UCG syngas utilisation options up to and including the injection of the captured CO_2 in the subsurface for storage.

5.1 Facility level assessment of emissions from lignite UCG syngas utilisation options

The results of the facility level emissions assessment of Lignite 2 UCG syngas utilisation options in terms of their life cycle impacts are illustrated in Figure 14. In terms of overall environmental performance, the UCG ammonia production and associated power with CCS performs better than the other two options, followed by UCG methanol production and associated power with CCS. UCG-IGCC power generation with CCS does not perform as well, as all the syngas is combusted and the corresponding air emissions are higher. However, UCG methanol production has a significantly higher GWP as significant amount of CO_2 emissions originate from the combustion of process gas that is generated by the methanol production unit (Figure 15). As expected, the abiotic resource depletion indicator score is identical for the three alternatives given that the reference unit used for the assessment is the utilisation of one tonne of coal.

All syngas utilisation alternatives have broadly the same FAETP, MAETP and TETP, originating from the incineration process, as all three processes produce the same heavy hydrocarbons and waste from raw syngas cleaning, the water gas shift unit and Selexol acid gas removal unit, which are combusted in the incinerators. UCG syngas utilisation in power generation with CCS has a significantly higher AP, EP, FAETP, MAETP and TETP than the methanol and ammonia production and associated power processes. This is due to higher emissions from the syngas combustion stack.

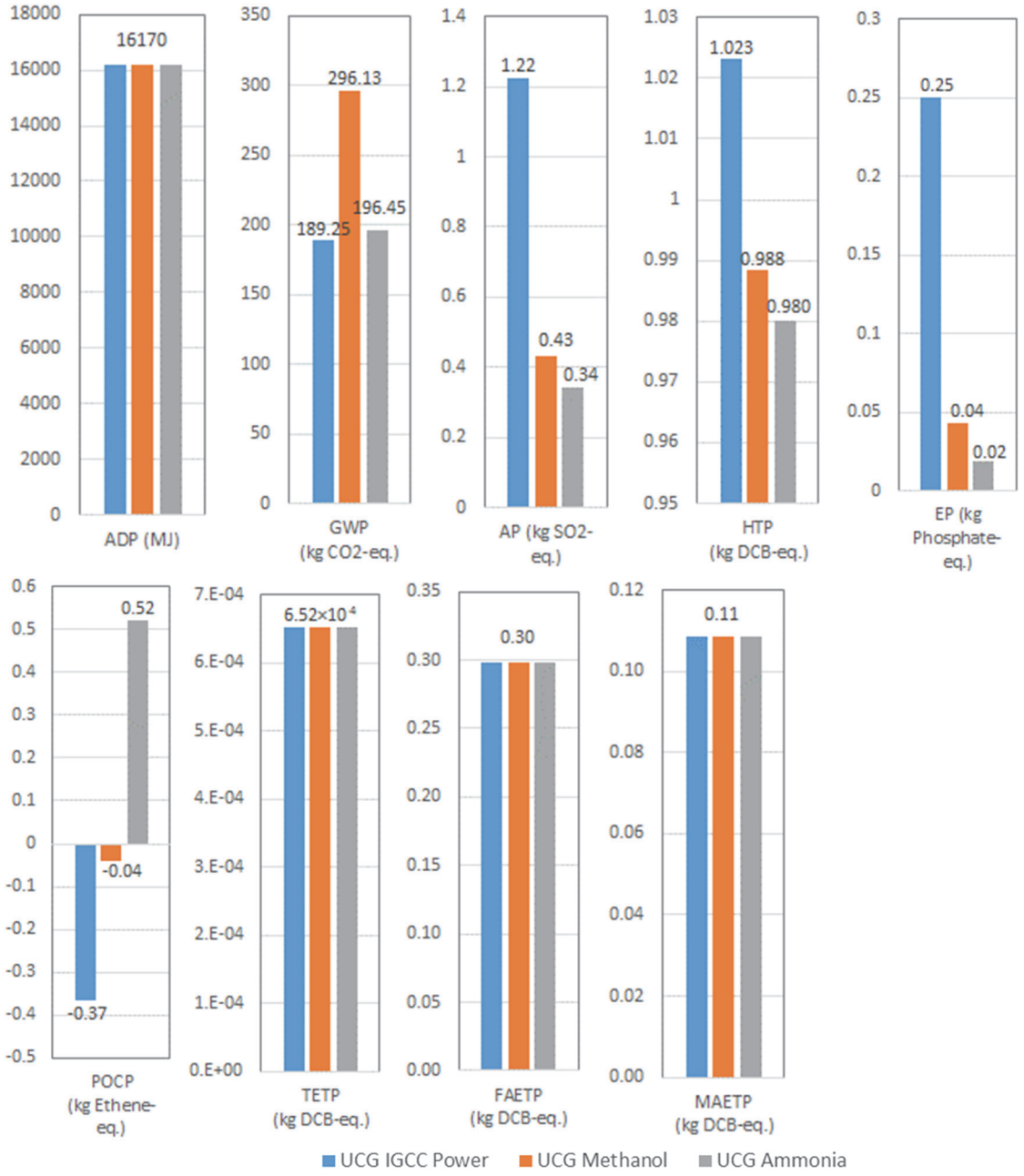


Figure 14. Comparison of the facility level emissions impacts of alternative UCG syngas utilisation options for one tonne of Lignite 2 gasified.

Figure 15 illustrates the source units for each category of emissions contributing to different life cycle impact categories. For all three alternative syngas utilisation options, the emissions primarily come from the process gas combustion stack, and the liquid and waste treatment incinerator. The level of detail in the LCI models developed also allows to track individual emissions at unit process level.

Figure 16 illustrates the key emissions from the three UCG syngas utilisation options at unit process level. Phenol emissions from the incinerator are the dominant emissions for FAETP, MAETP and TETP. Higher emissions of NO from the stack suggest that the UCG-IGCC power generation has a greater AP and EP than the UCG syngas utilisation in methanol production or ammonia production. Higher emissions of NO from the stack also result in a negative POCP for UCG-IGCC power generation. UCG with ammonia production has high CO emissions from the stack, therefore, UCG syngas utilisation in ammonia production has the highest POCP.

Please note that the downstream emissions from ammonia or methanol use are not considered within the context of this study.

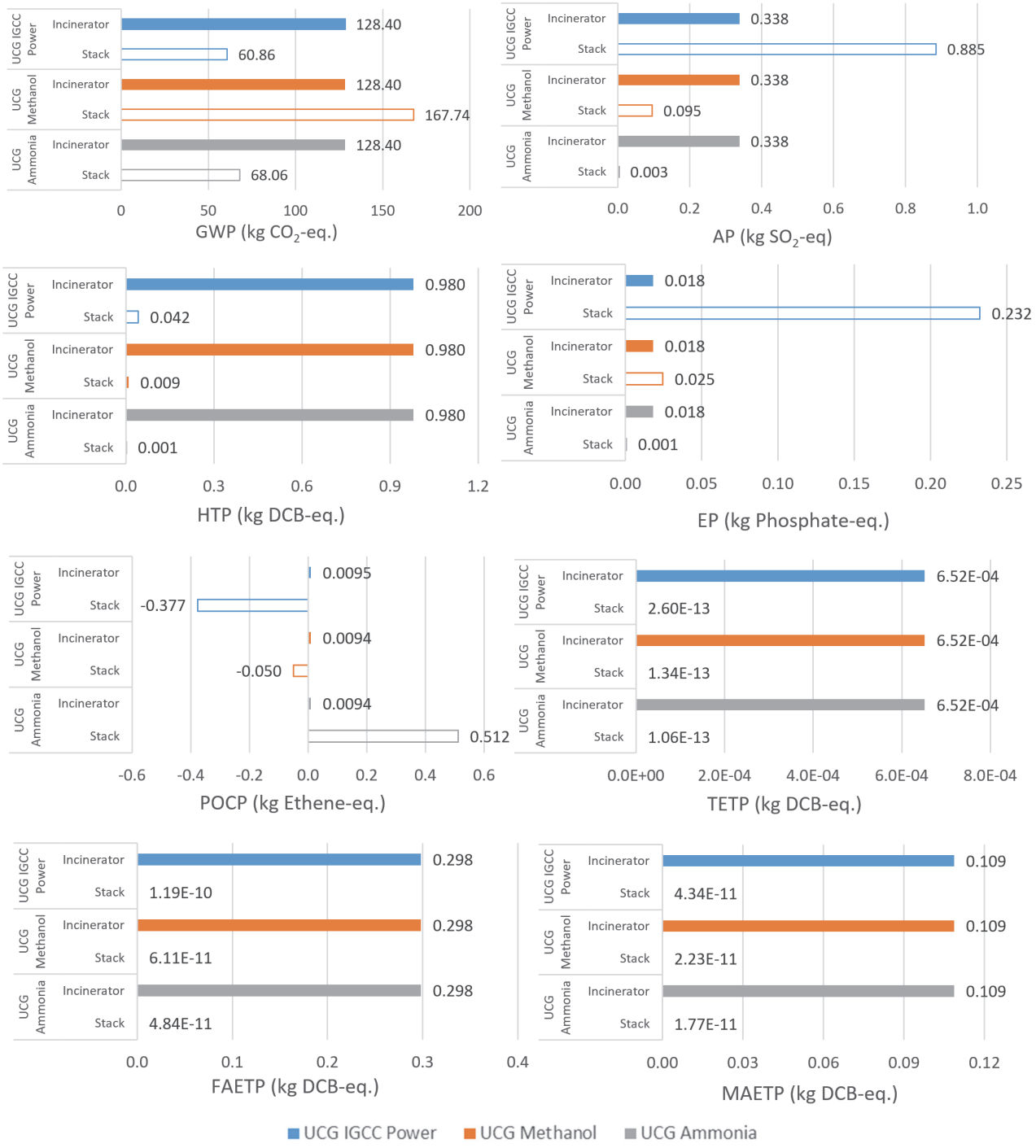


Figure 15. Comparison of facility level emissions impacts for the three UCG syngas utilisation alternatives at unit process level for one tonne of Lignite 2 gasified: Stack and Incinerator.

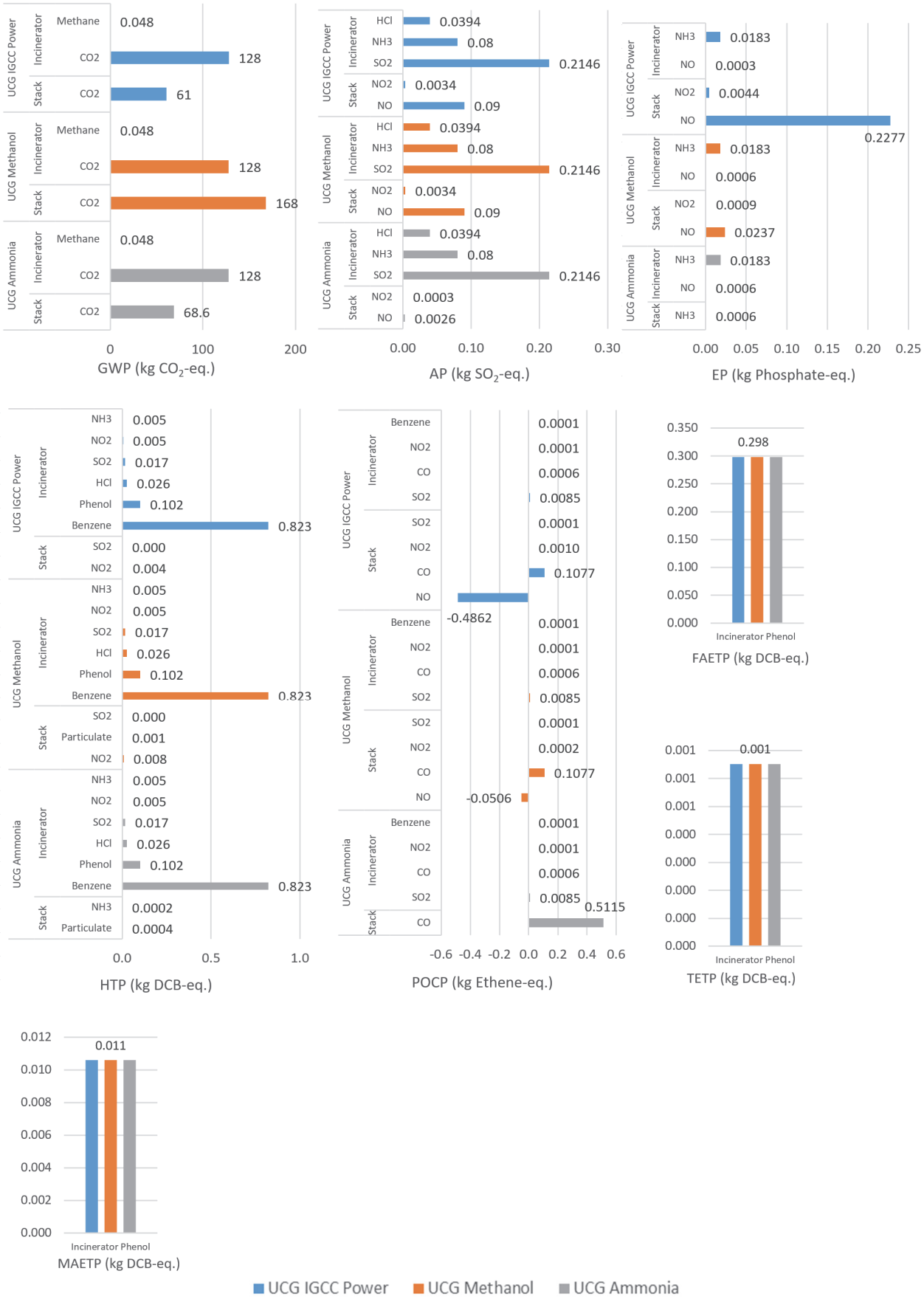


Figure 16. Individual emissions from the process gas combustion stack and incinerator contributing to facility level emissions impacts for the three UCG syngas utilisation alternatives per tonne of Lignite 2.

5.2 Life cycle analysis of lignite UCG syngas utilisation options

The whole chain life cycle analysis of UCG syngas utilisation for the three alternatives includes the upstream emissions from the supply of materials and consumables, including Selexol production, the infrastructure construction impacts, as well as CO_2 transportation and CO_2 injection for storage. The reference unit for this comparative analysis is one tonne of coal, same as in the preceding section.

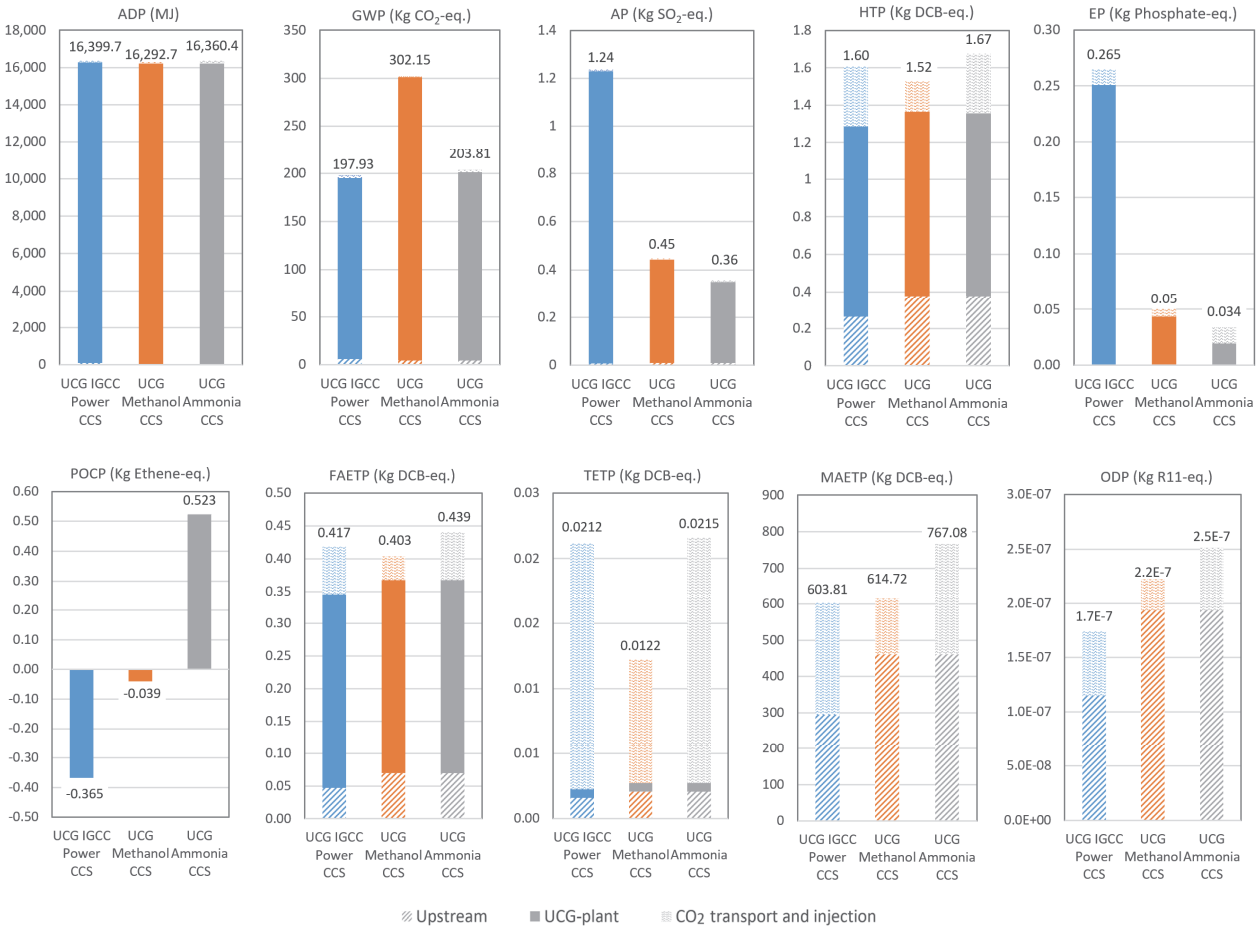


Figure 17. Comparison of the life cycle environmental impacts of alternative UCG syngas utilisation options for one tonne of Lignite 2 gasified.

The results presented in Figure 17 demonstrate that, for all three options, the whole chain life cycle environmental impacts ADP, AP, EP, POCP and GWP are dominated by on-site emissions from the UCG facility operations. For HTP and FAETP in particular, the upstream emissions and emissions from facility construction and CO_2 transportation are contributing the most. MAETP, TETP and ODP are also dominated by upstream and downstream process emissions with facility construction and CO_2 transportation being the main contributors. UCG methanol production with associated power and CCS is shown to release more life cycle CO_2-eq emissions per tonne of Lignite 2 consumed than that of UCG ammonia production with associated power and CCS and UCG-IGCC power generation with CCS. However, the amount of CO_2 that is generated for storage is lower in the case of methanol production (Table 10).

Table 7. UCG syngas utilisation option performance in terms of energy, product, CO_2 abatement and emission.

UCG options	Electricity generated (MWh/tonne coal)	Methanol production (tonne/tonne coal)	Ammonia production (tonnes/tonne coal)	CO_2 captured/stored (tonnes/ tonne coal)	CO_2 vented tonnes/tonne coal)
UCG-IGCC power with CCS	1.55	-	-	1.70	0.19
UCG methanol CCS	0.50	0.41	-	1.04	0.17
UCG ammonia CCS	0.40	-	0.43	1.69	0.20

5.3 Life cycle comparison of UCG syngas utilisation in methanol and ammonia production with conventional standards

In order to provide a meaningful comparison of UCG power generation and UCG methanol/ammonia production with associated power and CCS with industry standards, two different system expansion approaches were implemented and the results were expressed using a relevant functional unit. The reference production system emissions were taken from the UCG chemicals production with associated power and CCS system, allowing to compare the results. The two methods implemented are detailed in Table 11. Both methods suggest that UCG with ammonia production and associated power is significantly beneficial. Specifically, when system expansion is considered with a power generation focus, the case that is associated with ammonia features significantly lower and negative emissions in comparison to methanol.

When system expansion is considered with a chemicals product focus, the most substantial improvements in comparison to conventional chemical production are associated with UCG ammonia production. These compare favourably too with heavy oil, coal and natural gas based electrolysis, nuclear power based electrolysis cycles and even biomass based methods (Bicer et al., 2017). UCG methanol production with associated power generation also offers improvements in comparison to conventional methanol production, however, these are not as substantial.

Table 8. UCG syngas utilisation performance in comparison to industry standards.

ADP (MJ)	GWP (kg CO_2-eq.)	AP (kg SO_2-eq)	HTP (kg DCB-eq)	EP (kg Phosphate-eq)	POCP (kg Ethene-eq)	FAETP (kg DCB-eq)	TETP (kg DCB-eq)	MAETP (kg DCB-eq)	ODP (kg R11-eq)
System expansion for power generation with CCS (functional unit 1MWh)									
UCG methanol with associated power and CCS - Ecoinvent global average for methanol									
7,061	83.64	-0.98	-230	-0.43	-0.40	-125	-1.27	-31.9×10^{4}	-1.61×10^{-4}
UCG ammonia CCS - Ecoinvent global average for ammonia									
804	-1,737.22	-7.18	-1,404	-1.45	0.65	-300	-32.30	-122.4×10^{4}	-3.48×10^{-4}
System expansion for chemicals production									
Methanol (functional unit **1 tonne of methanol**)									
UCG methanol with associated power and CCS – electricity with CCS using UCG-IGCC									
27,033	583.20	0.13	2.35	-0.09	0.19	0.63	0.005	899	3.84×10^{-7}
Ecoinvent global average*									
31,300	637	2.26	279	0.63	0.38	150	1.55	383,000	1.93×10^{-4}
Ammonia (functional unit **1 tonne of ammonia**)									
UCG ammonia with associated power and CCS - electricity with CCS using UCG-IGCC									
28,160	354.30	0.09	2.83	-0.09	1.44	0.75	3.12×10^{-2}	1,319.77	4.61×10^{-7}
Ecoinvent global average*									
37,300	2,090	7.52	1,310	1.43	0.611	280	30.1	1.14×10^{6}	3.24×10^{-4}

* using CML 2001 characterisation method in Ecoinvent 3.5.

6. Conclusions

Research described in this paper developed life cycle (environmental emissions) inventory models for the UCG processes and three alternative syngas utilisation options with and without CO_2 capture and storage. The life cycle inventory models are developed at unit process level and are able to trace all important environmental emissions from UCG and across syngas utilisation options to their final release to the air, water and soil environmental compartments as gaseous, liquid emissions or solid waste. The models also account for coal seam quality, industrial scale panel designs, and UCG process operational parameters, which all serve as input parameters to the life cycle inventory model of the UCG process. The data used as input to the life cycle inventory models were determined through thermo-mechanical-chemical modelling of UCG reactor operations and geomechanical assessment of field scale UCG designs running at 3,210 tonnes/day coal gasified. Furthermore, LCI models for UCG site preparation, construction of surface facilities and injection well and production well drilling have also been developed and implemented. The alternative syngas utilisation option LCI models include power generation and two commercial products (ammonia or methanol) with associated power. The LCI models developed were not used to quantify the potential emissions to strata surrounding the UCG panels as it is assumed that the pressure in the underground gasifier is managed carefully and potential emissions to the strata surrounding the UCG panels are avoided.

Life cycle performance of two different conventional above ground coal fired power generation options (pulverised coal post-combustion capture and oxyfuel combustion capture) were compared with that of UCG-

CCGT power generation with/without CCS for two different lignites and one bituminous coal. One of these lignites was then used to compare the life cycle performance of different syngas utilisation options for power generation and the production of ammonia and methanol with associated power for the same underground UCG resource exploitation scenario

It has been shown that the coal resource characteristics affect significantly the syngas energy content and composition. The two lignites studied have also shown to perform differently with the lower energy content Lignite 2 producing a syngas with comparatively better energy efficiency and a similar life cycle GWP footprint per MWh electricity generated. The bituminous coal studied has a lower overall GWP footprint, but the energy efficiency of the process is not as favourable.

Comparison of the life cycle carbon footprint of conventional coal fired power generation with CCS and UCG-IGCC with CCS has shown that the in-situ methane content of the coal used, and methane emissions experienced during mining and the accompanying upstream processes are the key parameters in conventional coal fired power generation, whereas the UCG process dependent syngas composition is the key determinant of life cycle carbon footprint for UCG-IGCC power. It has also been shown that bituminous coal UCG-IGCC power plants with/without CCS have a greater life cycle carbon footprint than that of lignite UCG-IGCC and conventional surface power plants with/without CCS.

UCG methanol production with associated power and CCS is shown to release more life cycle CO_2-eq emissions per tonne of Lignite 2 consumed than that of UCG ammonia production with associated power and CCS and UCG IGCC power generation with CCS. When chemicals production from UCG is considered, the most substantial improvements in comparison to conventional methods are associated with UCG ammonia production. The results have shown that for all three syngas utilisation options, the whole chain GWP is dominated by on-site emissions from the UCG and plant operations.

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