Underground Coal Gasification - Evidence Statement of Global Warming Potential

DECC

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1. Introduction

This report provides a high level evidence statement on the global warming potential that the production and use of syngas from Underground Coal Gasification (UCG) would have, based on the likely end uses of the syngas, in comparison to current and conventional processes. It provides

1. An overview of the processes involved in UCG and where in those processes GHG may be released to the atmosphere.
2. Identification of the ranges of syngas composition and an estimate of its unabated global warming potential.
3. An identification of those gasses that can be captured and stored through CCS and the resulting mitigation potential.
4. An overview of the issues and the geological and technical feasibility of on-site sequestration of CO_2 in general terms.
5. An assessment of the potential greenhouse gas emissions due to both unabated and abated UCG syngas, in comparison to current and conventional processes.
6. An identification of the key evidence gaps on UCG GHG emissions

# 2. Overview of the UCG Process

2.1. The UCG Process

UCG provides a potential means for the recovery of energy from coal, particularly from relatively deep coal deposits that are uneconomic to mine.   The process involves the in situ gasification of coal with steam and either air or oxygen to produce a gas containing hydrogen (H_2), carbon dioxide (CO_2), carbon monoxide (CO) and methane (CH_4) as the major constituents, commonly referred to as syngas. However, to produce a gas of high caloric value (CV) and avoid a high dilution in nitrogen, it is necessary to use oxygen instead of air which requires an air separation unit. Such a gas is needed for both achieving high efficiencies in power generation using combined cycle gas turbines (CCGT) and to consider the production of fuels and chemicals.

For the UCG process an injection well and a production well some distance apart in the coal seam are required. The reactants, oxygen or air, and any added steam (together with an ignition source) are supplied to the coal seam via the injection well. The produced gases are extracted via the production well to the surface (Figure 2-1). As the coal reacts, a cavity is created in the seam. Directional drilling combined with a Controlled Retracting Injection Point (CRIP), where the point of injection is progressively retracted away from the production well, enables a relatively large volume of coal to be extracted by this means. Once the amount or quality of the gas produced declines, a new reaction zone is established by drilling new injection and production wells. Commercial-scale operations would involve a number of boreholes sets to produce sufficient quantities of gas for either large-scale power generation or for the production of fuels and chemicals.

Because the formation of the cavity can result in subsidence and also provide a route for tar escaping to cause groundwater contamination, relatively deep (over 600 m) (DTI 2004) and off-shore UCG is favoured on environmental grounds in order to avoid these potentially detrimental environmental effects. There is also a technical advantage from the increasing ambient pressure that occurs with increasing depth. The rate of gasification increases with depth, resulting in higher production rates for deeper coal seams. . The exact amount of the coal reserve that could be utilised for UCG is therefore very difficult to quantify, as it is limited by technical and environmental factors that are currently untested, rather than by the size of the coal resource itself. Although 'proven' UK hard coal reserves are relatively modest (264 Mt according to BGR's 2013 study,), the theoretical resource base is much larger, estimated at 186,700 Mt according to BGR 2013. There is considerable uncertainty in these figures, but there is clearly a very large potential resource base, as well as significant contribution to greenhouse gases. Initial estimates put 'good' UCG accessible onshore resource in the order 17 billion tonnes (BGS 2004). If this is limited for environmental reasons to the near shore North Sea reserves off the coast of NE England (see Section 4.2), then the potential resource is less than 5 billion tonnes, or about 12 billion tonnes of CO_2 if fully combusted. The potential GHG impact is discussed further in section 5.3.

Once the syngas has been extracted to the surface, it can be either transported offsite for utilisation after initial cleaning or it can be processed further at the point of production. These possibilities, along with their potential for greenhouse gas emissions and the potential for integration of UCG with Carbon Capture and Storage (CCS) are discussed in the following sections. However, in terms of the initial production, there is no inherent potential for direct GHG emissions unless there is an unintended escape (leakage) of the produced syngas. The initial gas clean-up generally only involves moisture, particulate and tar removal, with some potential for the removal of H_2S and other minor contaminants, such as hydrogen chloride, through gas scrubbed, dependent upon the quality of the gas required for the pipeline. **If fugitive emissions of gas are avoided then no direct CO_2 or other GHG emissions, other than those associated with typical day to day operational activities (fuel, water consumption etc.), should therefore occur at the point of production.**

Figure 2-1   Schematic of UCG in a coal seam
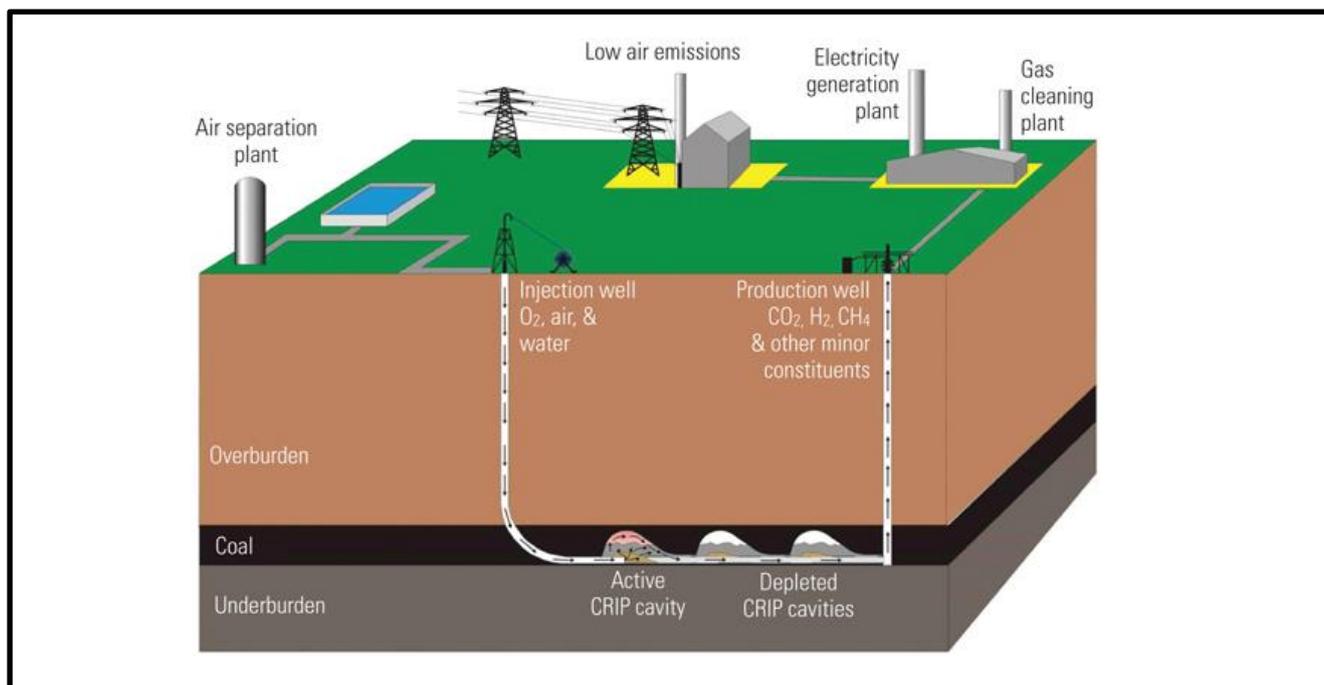
2.2. History of UCG and Current Developments

Comprehensive overviews of the many UCG trials that have taken place since the 1920s have been provided by Yang *et al.* (2015) and Burton *et al.* (2006). Between 1975 and 1996, over 30 pilot trials were carried out in the USA, testing bituminous, sub-bituminous, and lignite coals. The former Soviet Union also had over 50 years' experience of field tests with some commercial projects, including the power plant in Angren, Uzbekistan that is still in operation today after 47 years, where UCG is used to provide auxiliary gas fuel to a coal-fired power station. Another demonstration of co-firing coal and UCG gas has been undertaken at the Majuba power station by EKSOM, in South Africa. Since 1991, China has completed at least 16 tests, with several commercial projects for chemicals and fertilizer production. More recent and potential UCG trial locations are detailed by Yang et al (2015) and are summarised in Figure 2-2. In 1999, UCG activity in Australia was initiated by Linc Energy with a large pilot test (Chinchilla, Queensland) which produced syngas for 3 years, this was coupled with the construction of a gas to liquid pilot plant for diesel fuel (Yang *et al*., 2015). In another Australian trial, Carbon Energy Ltd, used UCG syngas in a 1 MW power generation unit. Other companies, including Cougar Ltd have attempted to pursue further trials. These Australian projects have, however, suffered from shallow depth and non-coherent overburden, which have had environmental issues which have led to plant closures.

UCG has been carried out on an experimental basis in Europe, with trials carried out at El Tremedal in Spain, and at two sites by the Polish Central Mining Institute. In the UK, a number of exploration licences for offshore UCG operations have been granted by the Coal Authority

Figure 2-2   Overview of recent global UCG projects (from Wang et al., J. Inst. Energy, 2015, 1-16)

3. Syngas Composition

The syngas obtained when oxygen, as opposed to air, is used for combustion in UCG is mainly composed of CO, H_2, CO_2, CH_4, with smaller concentrations of water, higher hydrocarbons (ethane, propane, butane), hydrogen sulphide (H_2S) and volatile tar constituents.

The exact composition of the gas that is likely to be produced from U.K. operations is very difficult to estimate because there have only been two trials at the sort of depths that are likely to be exploited for UCG development in the UK, namely the 550m test in Spain and the 1369m test in Swan Hills, Alberta,. Literature indicates that the trial nature of these studies meant that a higher proportion of coal was oxidised (rather than gasified) than would be expected under predicted operating conditions (DTI 2000, Vasilis et al 2015, Syngas Assoc. 2013). Averaging the expected <u>operational</u> outputs estimated from these trials results in a syngas composition of around 38% CO_2, 27% CH_4, 24% H_2 and 11% CO. These values fall within the range of compositions quoted for oxygen fed UCG in unpublished data (Mudashiru & Roddy 2014), although it is noted that most of that data relates to shallower, lower pressure conditions, which tend to have lower CO_2 and CH_4 percentages (circa 15% to 40% CO_2). Bhutto et al (2013) indicate that the calorific value (CV) of UCG syngas has an observed upper limit of around 10 MJ/m³, but that does not include values from the two deep, higher pressure studies quoted above.

There have been a number of published studies that have modelled the factors that contribute to variability in UCG syngas (for example Shafirovic & Varma 2009, Bhutto 2013). These show that the balance of gases is dependent on:

- the temperature and pressure of gasification;
- the proportion of coal consumed through the oxidation, gasification and pyrolysis processes..

The proportion of coal consumed by different processes is in turn dependant on a wide range of factors such as coal rank & permeability, UCG cavity geometry, pressure and operating temperature. The thermodynamics of the gasification reactions mean that there is a general increase in CH_4 and CO_2 at the expense of CO and H_2 as pressure increases. The converse is true for temperature – i.e. CO_2 and H_2 tend to increase as temperature increases (Bhutto 2013). Because temperatures tend to be higher within the gasification cavity itself, processes such as CRIP, which help to achieve a better linkage between the injection and extraction wells, also help to reduce the proportion of pyrolysis and oxidation combustion, so

should help to maintain overall reaction temperatures at values that are closer to 'optimal' conditions (i.e. >1200K).

In comparison to the syngas compositions quoted above, the syngas that is produced for power generation in above ground integrated combined cycle gasification (IGCC) of coal contains 90% CO plus H_2, with no methane and only *ca*. 10% CO_2. Crude export gas produced by above ground coal gasification using common methods such as the Sasol-Lurgi process generate syngas with a typical makeup of around 40% H_2, 20% CO, 30% CO_2 and 10% CH_4 (Turna 2007). The reasons why these values are different from UCG syngas can be explained through the reaction control factors described above, and in particular:

1. There is much less control on the reaction when gasification is carried out underground, so it can be difficult to maintain ideal temperatures, meaning higher rates of generation of CO_2 and CH_4.

2. The cooler walls and zone of connection between the cavity and the abstraction well can promote higher levels of pyrolysis, which primarily releases CH_4 (with some H_2). There is also a sizeable high temperature oxidation zone near the injection point, where CO_2 production dominates (Shafirovic & Varma 2009).

Based on the above, and using theoretical analyses such as those contained in Bhutto et al (2013) this would suggest a range of composition for oxygen/steam fed, deep (high pressure) UCG in the UK within the range described by Table 3-1below (% dry volume).

Table 3-1   Estimated Range of Potential UCG Syngas Composition for U.K. Developments

	Lower temperature gasification (<1000K), higher proportion of oxidation and pyrolysis (circa 20% each)	Higher temperature gasification (>1200K), smaller proportion of oxidation and pyrolysis (circa 10% each)
CO	8%	30%
H_2	17%	40%
CO_2	45%	15%
CH_4	30%	15%
Equivalent CV of Syngas (MJ/m^3)	13.6	13.5

These ranges cover the operational values quoted for the two previous deep UCG tests (DTI 2000, Vasilis et al 2015, Syngas Assoc. 2013), along with shallower tests from unpublished literature. They also reconcile with the 'typical' ratios of CO to H_2 of between 1:2 and 1:1 for combined oxygen/steam UCG indicated in other publications (Yang et al 2009, Seddon & Clark 2015). The CV is higher than the range of actual measurements quoted by Bhutto et al (2013), but that results from the deep, oxygen fed nature of the developments that are expected in the U.K.

4. Potential for Carbon Capture and Storage

4.1. Potential Uses of UCG Syngas and Technical Processes for CO_2 Removal

The options for CO_2 removal are largely dependent on the intended use of the UCG syngas. As discussed previously, it can be used in electricity generation or for chemical production, notably hydrogen, ammonia,

urea and methanol. Although the conversion of UCG syngas to liquid transport fuels (petroleum, kerosene etc) by Fischer Tropsch synthesis is used internationally, whether this becomes a major use in the U.K. given the present availability of much more economic sources of fuel hydrocarbons in the form of crude oil and natural gas depends on future oil and gas prices and any premium placed on indigenous supplies. Oxyfuel combustion could theoretically be used for power generation at the UCG site, but this is as yet unproven. A summary of the most likely potential uses of UCG syngas, and options for the removal of CO_2 associated with those uses, is therefore as shown in Figure 4-1 below:

Figure 4-1   Summary of UCG Applications and Options for CCS
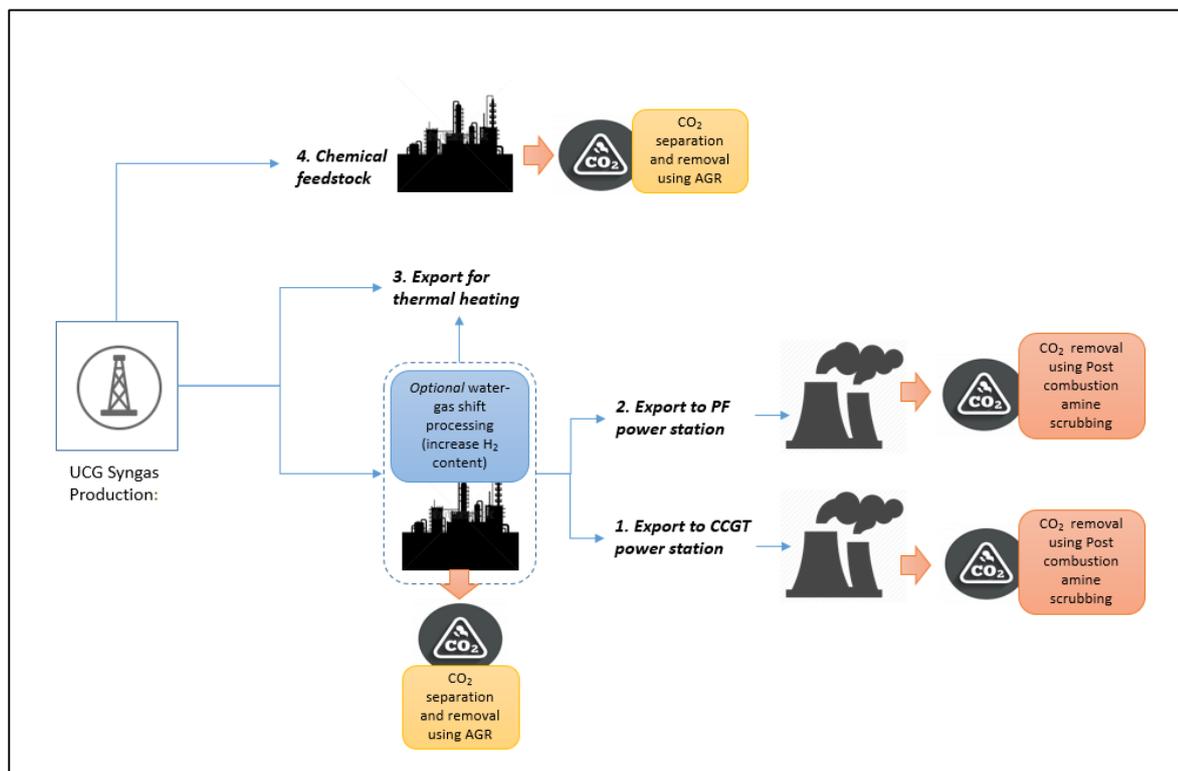
The technologies involved in removing the CO_2 and H_2S from syngas post transport at power generation or chemical processing plants are the same as those used in conventional power and processing industries. Effectively this means that CO_2 could be removed using one of the following two approaches:

- Using amine scrubbing on power plant flue gases,
- Using a standard Acid Gas Removal (AGR) system where CO_2 is produced as part of chemical processing. This includes the waste CO_2 that would be generated if water-gas shift reaction (WGSR) is used to replace CO with H_2 prior to combustion.

4.2. Regulatory, Geological and Economic Constraints on CO_2 Storage

The fact that cavities and associated subsidence fracture networks are developed during UCG within geological formations that are likely to be relatively deep (> 600m) and overlain by formations that provide strong barriers to vertical flow, means that on-site CO_2 storage using the developed coal formations could, on the face of it appear to be an attractive option for CO_2 mitigation. There are, however four significant issues associated with CO_2 capture and storage at the UCG target location:

1. **The ability to sequester all of the produced CO_2 within the UCG cavities is currently unclear.**
   Some recent research has concluded that the cavities created offer insufficient storage capacity for all the CO_2 generated from utilisation (Schiffrin, 2015). For example, based on the thermophysical properties of supercritical CO_2, Schiffrin calculated that the maximum achievable amount of CO_2 that can be sequestered in the cavities left after UCG is only 14%. The EU Bulgarian study of UCG and direct

CO_2 storage (Sheng et al 2013) proposed a value of 20.5%. Conversely, a summary review of recent research (Yang et al 2015) does suggest that all of the CO_2 could be sequestered within the cavity.

2. **There are potential environmental drawbacks associated with sequestration into the cavities**, in that the CO_2 (together with water) will act as a solvent for any remaining tar in the cavity,, which could result in CO_2 moving out of the temperature-pressure range for being supercritical and effectively boiling off (Burton et al., 2006).

3. **There are potential regulatory barriers.** The main piece of regulation for CCS across Europe is the EU CCS Directive on Geological Storage of CO_2 (Directive 2009/31/EC), which came into force on 25 June 2009. The Directive includes extensive requirements for storage covering the entire lifetime of a storage site. It is implemented in the UK mainly through the Energy Act 2008 (Chapter 3), which introduces a new regulatory framework to facilitate the offshore storage of carbon dioxide. This will require measurement, to monitor the stored CO_2 and verify that it is not migrating away from the storage site. This represents a significant cost and technical burden.

4. **There are logical scheduling/operational difficulties.** To capture all the CO_2 from the syngas at the point of production before it is used would require a multi-stage chemical process involving water gas shift reaction and CO_2 adsorption, which has both cost and power transmission implications. On-site power generation with post combustion capture would require that a dedicated CCGT power plant be built at the site. Both approaches would require that injection storage boreholes be constructed into the target coal seam, and there is an issue around the timing of the storage, which would not be available until the first underground gasification phase had been finished.

As there are no demonstration sites for sequestration of CO_2 into UCG cavities, further research would be required before it could be shown whether on-site sequestration is a viable option. Based on the above evidence, it appears that using on-site cavities and/or target coal seams to store CO_2 is a less attractive proposition than the two scenarios that are available for transport and subsequent removal of the CO_2 at a remote site, namely:

1. For power generation, transporting the syngas to a central site for power generation and utilising the post combustion facilities that are already available at the power generation site for CO_2 removal. If the power generation is located near to chemical production facilities (see below), then it would also be possible to carry out a water-gas shift reaction to convert as much of the syngas as possible into hydrogen before use in a CCGT power station. This has the potential advantage of allowing CO_2 removal prior to combustion, which would allow a greater overall reduction in CO_2 emissions if it is combined with post combustion scrubbing. It is noted that UCG syngas is well suited to pre-combustion capture because of the high CO_2 partial pressure.

2. For chemicals production, transporting the syngas into a wider 'cluster' of production sites that utilise various sources of raw materials (natural gas, coal etc.) to produce chemical feedstocks, with CO_2 capture and a centralised transport and storage facility.

5. Global Warming Potential

This section provides details of the comparison calculations and estimates made between the Greenhouse Gas (GHG) emissions associated with the main uses of UCG syngas, compared with its 'conventional' counterparts, natural gas and coal. A summary of the comparisons that are drawn is provided in Section 6 at the end.

5.1. Overview of Estimating and Comparison Methods Used

The sections below presents the GHG emissions of UCG syngas usage in comparison to the 'conventional' sources that are currently used to produce the same 'outcome' (energy or product). The most likely identified potential uses of UCG syngas are shown in Figure 4-1. Using these examples, four comparisons of GHG emissions from UCG syngas in comparison to 'conventional' sources are discussed:

1. A comparison of the CO_2e emissions from electricity production based on co-firing of UCG syngas with natural gas within a CCGT power plant. In this case the comparison is made between the UCG syngas itself and the natural gas that it would replace within the power plant feed.

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2.   A comparison of the CO_2e emissions from electricity production based on UCG syngas being used to assist in boiler heating within a pulverised fuel coal fired power plant.

3.   A comparison of the CO_2e emissions associated with using UCG syngas as a replacement for natural gas in domestic or industrial thermal heating

4.   A comparison of the CO_2e emissions associated with using UCG syngas as a replacement for natural gas in the production of common chemical feedstocks.

UCG syngas could also be used within 'cleaner coal' power plants (e.g. co-fired with coal syngas in IGCC), but such technologies are not yet mature. Some reference has therefore been made within the text where appropriate. Similarly, although UCG syngas is used internationally (e.g. Eskom in SA) to directly co-fire within PF coal power stations, the efficiencies are similar to those used for assisted boiler heating so additional comparisons have not been made for the sake of simplicity.

The comparison of GHG has been carried out at a high level, and the comparison calculations contain the following inclusions and exclusions:

- **Construction and Production:** the only energy consumption accounted for in production and consumption is that used for the on-site oxygen and steam generation used to provide injection gases for UCG. All construction activities, embedded carbon associated with construction materials, site operation and vehicle movements have been excluded, as these are currently too uncertain to allow a meaningful analysis for UCG. To allow a like for like comparison, those emissions have also been excluded from conventional coal extraction and natural gas extraction and refinement.

- **Transport.** Because the length and exact nature of transport of UCG syngas is not yet known, all GHG emissions associated with pipeline construction, pumping and leakage has been excluded (from the analysis of both the UCG syngas and 'conventional' fuels).

- **End Use.** GHG emissions associated with combustion for power generation have been included, along with estimates of relative generating efficiencies. Major power consuming processes associated with chemical production, plus CO_2 produced as a chemical by-product have been included in the comparison for chemical feedstocks. However, other factors such as relative differences in efficiencies of chemical plant operation are beyond the scope of this analysis.

- **CO2 removal.** The efficiency of the CO2 removal processes have been implicitly included within the removal efficiencies that are quoted (85-90% for post electricity generation capture and storage, and 90%+ for separation and storage associated with chemical production), but discussions about relative cost efficiency and/or economic viability of CO2 removal and sequestration is beyond the scope of this report.

As noted above, UCG in the UK is likely to require on-site oxygen and steam generation, which means production of UCG syngas may be more energy intensive than conventional fuels. Where UCG is oxygen blown, then power requirements associated with air separation also have to be taken into account. This is very difficult to estimate, as it depends on the source of the oxygen and the power used on site, however 'typical' net power losses relating to oxygen production for 'cleaner coal' integrated gasification combined cycle (IGCC) power plants are in the order of 5% to 10%, with newer air separation units at the bottom end of this range (Armstrong et al 2005, Doukelis et al 2015). Steam production power may be required in addition to this. It is possible to use power generated from expanding the high pressure syngas within an on-site turbine, which would offset some of the power requirements. Oxygen and steam production therefore potentially results in a net power loss of around 5% for potential UCG developments. Specific allowances for both initial oxygen/steam generation and process power requirements have also been made for chemical production, as power inputs are an integral and significant part of the comparison. The assumptions used are stated at the start of Section 5.5.

The above exclusions do introduce some uncertainties into the comparison (for example, although sources such as DECC 2013 indicate that emissions from gas transport or coal mining are small in comparison to those produced during power generation, some authors have indicated that they could be more significant). However, such sources are unlikely to be so significant as to affect the reliability of the overall conclusions presented within this report.

5.2. Power generation GWP Comparison

As noted previously, there are two potential likely uses of UCG syngas for power generation using 'conventional' technologies:

- Co-firing with natural gas in a CCGT
- Ancillary heat generation used to assist in boiler heating at a PF coal burning power station.

Direct feed into a dedicated gas turbine (GT) for UCG syngas is possible, and is being developed in China (DECC 2009), but the high hydrogen content of the syngas makes this problematic for conventional GTs, so modifications and additional costs would be required. The availability of natural gas powered CCGTs within the U.K, therefore means this is unlikely, and the use of UCG syngas as a minor feed (below half) into a natural gas powered CCGT is considered to be a more likely option.

For co-fired CCGT generation, using the range of syngas composition described in Section 3 with an assumed CCGT efficiency of 55%, results in emissions in the order of 570 to 785 g CO_2e/kWh. This compares with average emissions of 400 g CO_2 /kWh for natural gas powered CCGT (DECC, 2013). However, there are uncertainties over the effect that the use of UCG syngas might have on CCGT efficiency, even if it is co-fired as a minor component alongside the existing natural gas source. Because the combustion properties of H_2 and CO are quite different from those of CH_4, and require a significantly higher flow rate of syngas compared to natural gas for a given turbine size, modifications to the combustor, compressor, fuel system and turbine would be required to help maintain the CCGT's performance and reliability. In addition, hydrogen results in higher flame speed, higher flame temperatures and has significantly higher combustion speeds so diluents such as nitrogen or steam may be required to lower the flame temperature in order to limit formation of NO_x as the syngas is combusted. If these issues were not addressed, carbon emissions would be expected to be higher than those quoted.

UCG syngas is used for boiler based power generation in China, and so could feasibly be used to support conventional pulverised fuel coal power plants in the U.K. Obviously this would require modifications to the plant. Not surprisingly, the calculated CO_2 emissions for UCG syngas used this way, at 875 to 1200 gCO_2e/kWh (assuming 36% efficiency), are quite similar to those quoted for conventional coal fired power stations (900 g CO_2 /KWh based on DECC, 2013). This, combined with the need for modification, widespread closure of PF combustion plant, the significant distances between remaining plants, and the likely location of UCG trials on the east coast of the UK, means that power generation using this approach is unlikely in the UK context.

The above values represent unabated GHG emissions. Post combustion carbon capture and storage (using amine scrubbing) can reduce conventional PF power and CCGT to around 111 gCO_2e/kWh and 55 gCO_2e/kWh respectively (IEA 2011). Although evidence based figures are not currently available, because UCG syngas would be used with conventional post combustion technology, it is reasonable to assume that a similar CO_2 reduction ratio could be achieved, resulting in circa. 70 to 100 gCO_2e/kWh for UCG syngas in a CCGT power plant with CCS, and 100 to 150 gCO_2e/kWh for UCG in a coal fired power plant with CCS. The uncertainty on this is larger than the unabated figure, as there is little evidence on the actual CCS performance for UCG power plants.

As discussed in Section 4.1 and shown in Figure 5.1., it is possible to use WGSR to replace the CO within the syngas with H_2 prior to combustion. Whilst this would generate additional CO_2, this could be captured (using an AGR) and sent for storage. This would allow 'cleaner' combustion, and could result in very low final carbon emissions from the UCG component of CCGT, potentially achieving emissions around 30 gCO_2e/kWh, However, it is important to note that at this level of CO_2 efficiency, the amount of power, raw materials and disposal routes for the CO_2 capture and storage become significant, and are not accounted for within the comparative factors allowed for in this report. Economic feasibility also reduces as more processes are added to the UCG power generation stream. A much more detailed life cycle accounting calculation would therefore be required to meaningfully compare UCG and natural gas under such scenarios.

Finally, UCG syngas could also be used for co-combustion within 'cleaner coal' integrated gasification combined cycle (IGCC) plants. This would be significantly less CO_2 intensive than PF combustion (with the future possibility of being less intensive than current CCGT), but as the technology is not mature and there are limited data available for operation with UCG syngas, it is not realistic to try and place a figure on the

likely emissions from such a usage at this stage. IGCC using standard coal feed, typically produces 793 gCO_2e/kWh (reducing to 115 gCO_2e/kWh with CO_2 capture and compression, IEA 2011).

A summary of the above comparisons is provided in Table 5-1below.

Table 5-1   Summary Comparison of GHG emissions from Power Generation using Syngas Versus 'Conventional' Fuels

GHG scenario		Power Generation Technology (all values quoted in gCO_2e/kWh)		
		CCGT	PF	IGCC
Unabated GHG emissions	Conventional Fuel only (typical value)	400	900	793
	UCG syngas component (range)	570 to 785	875 to 1200	Similar to conventional fuels
GHG emissions with CCS (amine scrubbing post combustion)	Conventional fuel only	55	111	115
	UCG syngas component	70* to 100*	100 to 150	Similar to conventional fuels

It may be possible to further reduce carbon emissions through WGS of the syngas, with associated AGR removal of CO_2 prior to combustion – see above.

5.3. Power generation – Total GHG emissions from UK coal resource the UCG Resource

In order to estimate the total unabated GWP if the entire UCG reserve is used for electricity production, a number of assumptions are required, as shown below:

- Assume average quality UCG syngas produced from coal stock at the lower end of potential reserves (limited due to environmental constraints at 5 billion tonnes coal - see Section 2.1).
- Assume a typical high volatile coal containing 80% dry ash fee carbon and 10% moisture and 10% ash, therefore carbon content as received is 64%.

On a simplistic basis, assuming all of the carbon within the coal ultimately generates CO_2 a 5 billion tonne reserve would produce something in the order of 12 billion tonnes of CO_2e (64% carbon by content, multiplied by the molecular mass of CO_2, 44, divided by the atomic mass of carbon, 12). Abated, in line with the CCS efficiencies described above (effectively 80% to 90% removal) and assuming that post combustion CO_2 CCS is applied, this would reduce to approximately 0.6 to 1.8 billion tonnes CO_2e. Obviously there is a very wide range of uncertainty around these figures, relating to the size of the reserve, the coal composition, the syngas composition and the efficiency of the CCGT technology with UCG syngas. Policy and economics may tend to limit UCG to those coal reserves with a lower CO_2 production potential, so the range is likely to have a downside risk. To set this in the context of a single carbon efficient, commercially viable UCG development consuming 2 MMTPA of coal, and using the figures discussed above for CCGT power use, this would emit something in the order of 4.4 MMTPA CO_2e, reducing to something in the order of 0.5 to 0.9 MMTPA $CO_2e$for UCG that incorporated CCS.

5.4. Thermal Heating

The low methane concentration of UCG syngas means that it is unlikely to be useable for domestic or smaller scale industrial heating, as this would require specific modification for each heating system where it is used. Direct thermal heating may be possible in larger facilities, but it is noted that the CV of UCG syngas is less than 1/3 that of natural gas (circa. 13 MJ/m^3 for deep, oxygen fed UCG, as calculated in Section 3, versus approximately 45 MJ/m^3 for natural gas). This means that direct thermal heating is only likely for facilities that currently have direct coal fired boilers.

Because it is too energy intensive to attempt to increase the methane concentration, the only realistic potential for thermal heating is if the syngas is hydrogen enriched to provide a hydrogen fuel for use in appropriately converted or manufactured boilers or CHP systems. Currently the adoption of hydrogen for thermal heating outside of industrial process engineering is very limited (Dodds et al 2014), but if hydrogen is adopted as a source of supply, particularly associated with renewable energy generation, then it would be feasible to use UCG syngas to generate hydrogen for thermal heating. **The processing and comparison of warming potential in the production of hydrogen from UCG syngas is detailed within Section 5.5 below.**

5.5. Chemical Feedstocks

Overview

The most likely use of UCG syngas for chemical feedstock production will be in the generation of hydrogen, ammonia or methanol (Binderman and Spero 2002). In all cases the potential greenhouse gas emissions can be compared to the obvious alternative – i.e. chemical feedstock production using natural gas.

As noted in Section 5.1, power requirements have been included in a limited way within the comparison of CO_2 emissions for chemical production, and include:

- The additional power required for the air separation unit (ASU) used in generating the oxygen for the UCG process, included as 70MW for a 'typical' plant.
- The power required for steam generation for the UCG process and Steam Methane Reforming for both natural gas and UVG syngas (see below), based on 2758KJ/kg (at 80 bar) for steam production, using a 90% efficient natural gas fired boiler.

Before UCG syngas or natural gas can be used for chemical production, the methane content first of all has to be converted into H_2 and CO/CO_2 using a process known as Steam Methane Reforming (SMR), which requires a significant amount of energy input to generate the steam for reaction. This stage is common to both types of gases, but obviously the amount of methane involved is very different (up to 90% for natural gas, compared to up to 30% for UCG syngas). For UCG syngas, methanol and hydrogen production then follow similar stages. An overview comparison of the processes involved is provided diagrammatically in Figure 5-1.

A comparison of the amount of CO_2 generated from UCG syngas in comparison to natural gas is provided in the following sections. In all cases, CO_2 is separated from the gas streams during production as a normal part of the processing. It is therefore theoretically possible to capture all of the CO_2 generated from UCG if the syngas is used in chemical feedstock processing, although solvent-based techniques are then required to allow final capture and then storage of the CO_2, (Bonaquist 2010), which means the overall removal efficiency can only be in the order of 90%.

On a comparative basis it is not readily feasible to compare the CO_2e generated from UCG in comparison to natural gas if CCS is included. This is because natural gas has much higher methane content than UCG syngas. As shown in Figure 5-1, this needs to be converted into hydrogen using Steam Methane Reforming (SMR) prior to the main processing stages. This requires a large amount of power, generating associated CO_2e. The exact processing approach that would be used for UCG depends on the relative composition of the syngas, but in most cases SMR of the methane, combined with the raw H_2 content, should be sufficient to provide an acceptable $H_2:CO$ ratio for methanol production. This means that the difference in energy consumption associated with UCG based methanol consumption that included CCS may not be that different from natural gas based methanol production that included CCS. Wider lifecycle considerations would therefore be required in order to provide a meaningful comparison at the low levels of net CO_2 emissions associated with CCS.

Because of these issues, a comparison of abated global warming potential was therefore excluded from the scope of this evidence report, and all comparisons are simply provided on the basis of unabated global warming potential. If CCS were used, then a much more detailed analysis of the heat capture and efficiency of the hydrogen production plant, along with an analysis of the tonnage, raw materials and disposal routes of the carbon capture side of the CCS process would be required.

Figure 5-1   Steps Involved in the Synthesis of Chemical Feedstocks from UCG Syngas
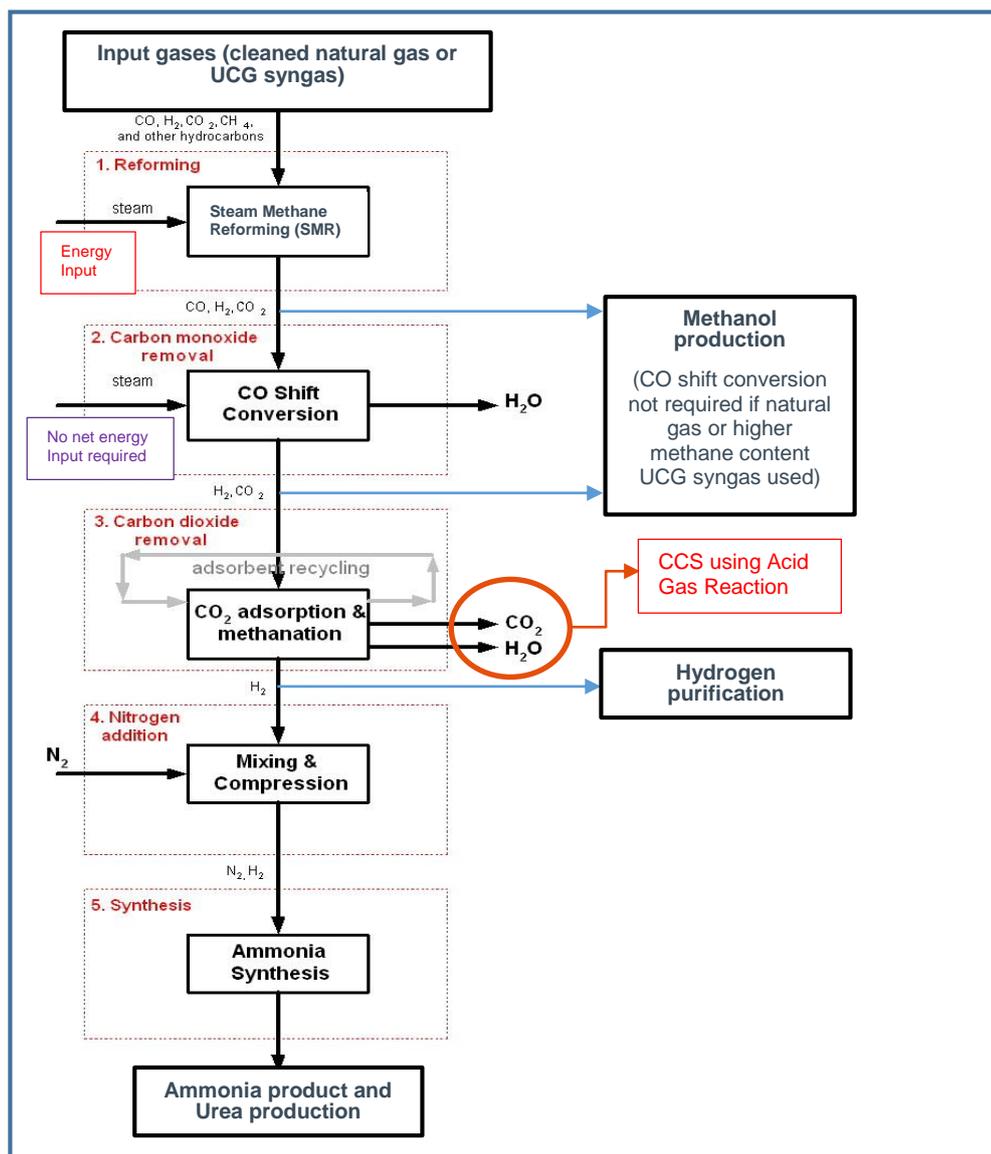
Methanol Synthesis (Unabated)

Methanol is used as a chemical feedstock for a range of important industrial chemicals, such as acetic acid, formaldehyde and ethylene, and is also used directly as a fuel or fuel supplement. Because reformed natural gas results in a syngas with relatively high hydrogen content (75% H_2), it is well suited for methanol synthesis and depending on the price of natural gas, is the least expensive process. However, coal-derived syngas is becoming more popular with coal/solid feed stocks contributing to around 9% of the worldwide output of methanol (Higman & Van der Burgt M 2008)

On a general basis, catalytic conversion of coal-derived syngas into methanol is achieved through a combination of heat generating (exothermic) reactions. For UCG syngas this may require WGSR (NETL 2015a), which would add to CO_2 generation., but only if pre-processing SMR of the methane content is not carried out for some reason. This seems unlikely, as the methanol reactions are highly exothermic, so the excess heat of reaction can be recovered to make steam which is then used for SMR and to generate power for the plant. In addition, low pressure purge gas can also be burned in boilers to help produce power and steam to meet, and in some cases to exceed, in-plant power demand. A comparison of the CO_2 production associated with methanol production from UCG in comparison to natural gas can therefore be summarised as follows:

- Power consumption and CO_2 generation associated with the conversion of natural gas into a hydrogen rich syngas (circa 75% hydrogen by volume). On an industrial scale using modern processes, this is in the order of 6 tonnes CO_2e per tonne of hydrogen (H_2) produced within the syngas (derived from Bonaquist 2010).

- Power consumption and CO2 generated from UCG depends on the composition and hence processes involved. However, most of the range of potential syngas composition described in Section 3 would only require SMR of the methane content within the syngas prior to methanol synthesis. Based on the range of compositions quoted in Section 3, and allowing for direct process emissions of 1 mole CO_2 per 3 moles of H_2 generated from the SMR, plus the following heating and power assumptions:

    o Steam power requirements as stated previously (applied to oxidation of the coal, plus SMR of all methane in the syngas)

    o Oxygen production requirements at the UCG site (as stated previously),

    o A 1:1 ratio of oxygen:steam for the UCG gasification process

  this would generate between 9 and 17.5 tonnes CO2e per tonne of hydrogen (H2) produced.

- In both cases, the H_2 and CO within the syngas would then have to be synthesised into methanol. Accounting for the atomic weight of methanol results in approximate emissions of around 0.75 tonnes CO_2e per tonne of methanol produced from natural gas. This compares with a range of around 1.1 to 2.2 tonnes CO_2e per tonne of methanol produced from UCG syngas.

The above calculations assume that all of the UCG syngas is converted into methanol.

The nature of the catalytic conversion process used in methanol synthesis means that input gases can only contain less than 1% CO_2 (by volume) (Crocker 2010). Any excess CO_2 would therefore need to be separated out immediately prior to the compression of the gas for injection into the catalytic stage.

Hydrogen and Ammonia Production (Unabated)

Similar to methanol, the majority of hydrogen and ammonia is manufactured via steam reforming of natural gas. However, in regions lacking inexpensive natural gas, such as China, coal gasification is very important for ammonia production. In 2008, 97% of China's ammonia production used coal, a trend which is expected to continue and increase (NETL 2015b).

To generate the 'pure' hydrogen requires that the remaining CO within the syngas is converted into CO_2 plus H_2 using WGSR. This is more carbon intensive than the SMR reactions described under methanol generation, and, assuming power consumption requirements as stated for methanol, overall results in estimated emissions of 9 tonnes CO_2e per tonne of hydrogen (H_2) produced from natural gas (derived from Bonaquist 2010). For UCG syngas the range is between 12 and 17 tonnes CO_2 per tonne of hydrogen (H_2) produced.

For ammonia generation, the purified hydrogen is reacted with nitrogen in the Haber Bosch reaction to form ammonia. This does not involve the consumption or generation of any additional CO_2, so the comparison remains the same as that provided for hydrogen production, although on a unit weight basis the values are lower due to the higher mass of ammonia. This results in approximately 1 tonne CO_2e per tonne ammonia produced using natural gas, compared with around 1.3 to 1.9 tonnes CO_2 per tonne of ammonia produced using UCG syngas.

Some of the CO_2 produced during hydrogen synthesis can be consumed if ammonia is then used to produce urea (one of the principal ammonia products and the basis of many fertilisers). However, as only 1 unit (mole) of CO_2 is required for every three units of hydrogen this means that the process based on natural gas already provides excess CO_2 for the urea reaction, the CO_2 generated is still the same in relative terms.

Summary of Global Warming Potential from Chemical Feedstocks

Based on the evidence provided above, the following comparisons have been drawn between 'conventional' feedstock (natural gas) and UCG syngas.

Table 5-2   Comparison of <u>Unabated</u> GWP for UCG Syngas against Natural Gas as a Chemical Feedstock

Chemical Synthesised	GWP based on natural gas feed (tonnes CO_2e/tonne of product)	GWP based on UCG syngas (tonnes CO_2e/tonne of product)
Methanol	0.75	1.1 to 2.2
Hydrogen	9	12 to 17
Ammonia	1	1.3 to 1.9

As noted previously, the options for carbon capture and storage if UCG syngas is in chemical production are very good, with conventional technologies (AGR) potentially achieving CO_2 removal of over 90%. This applies to both natural gas and UCG syngas.

6.   Summary of Global Warming Potential

In summary, it is feasible to compare the GHG emissions from UCG against 'conventional' sources that are currently used to produce the same outcome. Based on the available evidence, the following comparisons have been drawn:

- Power generation:
    - The most likely option for power generation from UCG syngas is based on co-firing with natural gas within a CCGT, as this is the most economic and carbon efficient option. There is a large range of uncertainty associated with the GHG emissions as a result of uncertainties over syngas composition and combustion efficiency. However, it is estimated that the UCG syngas component would result in emissions that are between 40% and 100% higher than the natural gas fed component in a combined feed power station.

    - If simple post combustion CCS is used, then the emissions comparisons quoted above remain valid as a percentage range (i.e. UCG syngas emissions are still around 40% to 100% higher than natural gas). However, it may also be possible to carry out a water-gas shift reaction on the UCG syngas prior to combustion, which would allow pre-combustion CCS to be carried out. This could, theoretically, reduce the emissions associated with UCG syngas to very low values (as low as 30 g CO_2e/KWh, compared with around 55 CO_2e/KWh for natural gas).However, it is important to note that at this level of CO_2 efficiency, the amount of power, raw materials and disposal routes for the CO_2 capture and storage become significant, and the levels of hydrogen involved are likely to require a dedicated (rather than co-fired) CCGT plant. Economic feasibility also reduces as more processes are added to the UCG syngas power generation stream. A much more detailed life cycle accounting calculation would therefore be required to meaningfully compare UCG and natural gas under such scenarios.

    - Based on the above, and assuming 5 billion tonnes of potential coal reserves, the total unabated GHG emission due to UCG is in the order of 12 billion tonnes of CO_2e, reducing to something in the order of 0.6 to 1.8 billion tonnes CO_2e if CCS is incorporated as part of power generation from the UCG syngas. An unabated, carbon efficient, commercially viable UCG development is likely to emit something in the order of 4.4 MMTPA CO_2e, reducing to something in the order of 0.5 to 0.9 MMTPA for UCG that incorporated CCS.

- Heating

    Use of UCG syngas for heating would generally require the use of hydrogen, which means the comparison is therefore largely the same as for hydrogen feedstocks below. Direct thermal heating may be possible in larger facilities, but it is noted that UCG syngas has less than 1/3 the calorific value of natural gas.

- Chemical Feedstocks

    o   For methanol production, the unabated GWP of UCG syngas is likely to be more carbon intensive than natural gas, at between 1.1 to 2.2 tonnes CO_2e per tonne of methanol produced, compared with 0.75 tonnes CO_2e per tonne of methanol produced for natural gas. For hydrogen the comparison is around 12 and 17 tonnes CO_2e per tonne of hydrogen (H_2) produced for UCG, compared with around 9 tonnes CO_2e per tonne of hydrogen from natural gas. It is noted that the opportunities for CCS associated with chemical production are very good, potentially achieving carbon removal of greater than 90%.

7. Key Evidence Gaps

The main evidence gaps regarding greenhouse gas emissions of UCG relate to:

- The size of the potential reserve, and the trade-off between this and the level of GHG emissions from UCG is uncertain, as lower GHG emissions could be achieved if UCG is limited to more efficient resource areas. At the moment the quality of syngas (and hence CO_2 emissions) is still very uncertain, as are any economic constraints that might effectively limit the size of the potential economically accessible reserve.

- The size of potential fugitive emissions has not been considered here, as the level of need for operational practices such as flaring is uncertain. Similarly, the potential GHG emissions resulting from SO_x have not been considered, as it is assumed that any significant sulphur content would removed during initial gas cleaning on site, but again, this is not certain.

- The efficiencies that could be achieved if UCG syngas is used in CCGT power generation, as the modification and operation has not yet been analysed in detail.

- The feasibility of using the UCG cavities for CO_2 sequestration is open to debate. As discussed within the body of this report, the most likely current UCG development sites are in the north east of England and eastern Scotland, as there is the potential for industrial (chemical) use of the UCG syngas along with power generation. This means that carbon capture that then feeds into a centralised storage facility for regional industrial 'clusters' is a possibility for the UCG development. However, if UCG is developed at other locations, then the options for CCS are currently unclear.

- Where CCS is proposed, both for power generation and chemical feedstock production, then more detailed life cycle analyses are required to evaluate the comparative CO_2e production between UCG syngas and natural gas.

- Use of UCG syngas to produce transport fuels. Inclusion would not be straightforward since conventional technologies rely on a completely different supply chain (crude oil exploration and refining) and there are widely different views regarding which pathway the UK should be following with respect to fuelling transport.

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