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King coal: restoring the monarchy by underground gasification coupled to CCS

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Abstract: Coal has hitherto been seen as a potential fall-back resource as hydrocarbons become depleted. However, amidst anxieties over peak oil and gas, some recent studies have painted a picture almost as gloomy about the longer term prospects for coal. Such evaluations are misleading, as they identify as reserves only that coal accessible at reasonable cost by means of conventional mining, which are increasingly modest compared with deeper-seated coal reserves amenable to underground coal gasification (UCG) using directionally drilled boreholes from the surface. Significantly for the petroleum industry, the technological requirements for UCG are far more akin to those of oil and gas production than they are to those of deep mining. A number of projects around the world are revealing the feasibility of UCG. We highlight preliminary findings from a recent investigation of the potential for UCG in NE England, which has the longest history of conventional coal mining at industrial scale anywhere in the world. Despite this history, fully 75% of the coal resources in NE England remain in place. A significant proportion of these is likely to move to the 'reserves' register as underground gasification technology begins to be deployed. A particular attraction of UCG lies in its suitability for coupling to CCS: we can use our long-standing knowledge of the response of incumbent strata to longwall coal mining to predict substantial increases in permeability in and immediately above the voids created by gasification. As these engineered zones of high permeability will already be connected to surface power plants by the wells and pipelines used to produce synthesis gas during gasification, they represent ideal prospects for permanent sequestration of a large proportion of the carbon dioxide arising. Stored CO_2 will be kept in place by cap rocks higher up in the sequence.

Keywords: carbon dioxide, CCS, coal, gasification, *in situ*, reserves, UK, underground, wells

Most forecasters are now confident that 'Hubbert's Peak' – the global peak in oil production – will occur some time in the five years from 2017 to 2021 (e.g. Strahan 2008). The global peak in natural gas will follow a few decades thereafter. As Hubbert's Peak looms into view, the economics of petroleum production are finally shifting in favour of long-known but as yet little-exploited unconventional resources, such as the Athabascan tar sands, oil shales, shale gas and its close relative coalbed methane. Exploitation of coal itself, rather than the methane it contains, has often been identified as the best long-term prospect for maintaining global energy supplies beyond the maximum 50-year horizon offered by nuclear (Trainer 2006). However, atmospheric CO_2 emissions associated with conventional use of coal are the worst of all the fossil fuel categories, so that (outside of the developing world at least) strong resistance to increased coal use is now being experienced, due to concerns over runaway climate change. Opponents of increased use of coal rightly point to the ultimate need to move to a wholly renewable energy economy. Even in the absence of a need to combat climate change, this would still be the only option eventually, once all energy minerals have been exhausted. However, as Trainer (2006) has shown, all available renewable energy resources, exploited using all known or reasonably anticipatable conversion technologies, are insufficient to meet the extravagant demands of a modern consumer society, and will thus be very far from sufficient for a larger global population, especially if the developing countries aspire to levels of consumption already typical of the Global North. Furthermore, no-one has yet devised a renewable energy technology that does not require industrial-scale manufacturing to produce its component parts – and many of these manufacturing processes (e.g. production of steel) rely on continued use of coal. It is therefore likely that coal use will continue, and indeed expand worldwide in coming decades, not only while we develop better renewable technologies, but also while macro-economic adjustments take place (by design or disaster) to lower energy demand per capita in wasteful consumer societies.

Many commentators have complacently assumed that coal reserves are sufficient to support several centuries of exploitation without exhaustion. More recently, concerns have been expressed about some of the assumptions on which the more optimistic projections have been based (e.g. Strahan 2008). However, the pessimistic downgrading of likely reserve estimates is based on a fundamental assumption which cannot be left unchallenged: namely, that coal will only be exploited using conventional mining, which has depth limits of about 1500 m (because of severe floor heave issues), and is usually not economic below depths of a few hundred metres. If the possibility of underground coal gasification (UCG) is taken into account, the world's usable coal reserves are increased by a factor of at least three (McCracken 2008), and this increase will be achieved without the risk to life and limb posed by deep mining. Coupled with carbon capture and storage (CCS), UCG also offers a highly attractive carbon management option whereby most of the CO_2 arising can be permanently sequestered back in deep subsurface voids produced by the UCG process itself. If implemented at commercial scale, UCG with CCS (UCG–CCS) offers mankind's last, best 'bridging technology' to the inevitable renewable energy economy of the future.

A brief history of UCG

Although briefly postulated by Lord Kelvin in the late 19th century, the first UCG experiments were actually carried out by Sir William Ramsay (the discoverer of the noble gases), in 1912 in County Durham, NE England. Although these experiments were successful, further progress was halted by the First World War. Relatively

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low prices for oil and gas meant that for many years there was limited interest in further development of the technology. Nevertheless, a number of countries around the world have developed UCG operations. Most notably these have included the former Soviet Union and China, where commercial-scale operations have been conducted. Feasibility studies or trial operations have also been conducted in Australia, the USA, Spain, South Africa, India and the UK. The Underground Coal Gasification Partnership (UCGP) has estimated that around 20×10^9 m^3 of syngas have been produced to date from UCG activities across the world, equivalent to about 15×10^6 tonnes of coal. To date, the largest power generation plant based on UCG is a 100 MW steam turbine plant at Angren in Uzbekistan.

The focus of early trials such as those carried out in the former Soviet Union from 1930 and in China was on finding ways of controlling the underground gasification process, developing effective ways of drilling the injection and production wells, and of linking the two wells as a precursor to gasifying the coal. Most of this work can only be done at a significant scale in real coal seams, so trials tended to be expensive. In time the trials became bigger and longer in duration up to a point where it became sensible to build power generation facilities to run off the syngas being produced from an ongoing programme of coal seam gasification. Europe started to look at UCG during the 1950s and 1960s. Meanwhile, trials in the USA developed new variants on UCG technology and also explored more carefully the potential environmental impacts (Burton 2007). During the 1970s and 1980s, 32 separate tests were carried out along with a large supporting development programme. The main centre of interest was the Powder River Basin in Wyoming. One outcome from all of this was the development of a new control technique called ‘moveable injection’ (Friedmann 2008). Some work was also done on routes to chemicals production from syngas as an alternative to power generation. India started looking at UCG in the 1980s.

By the early 1990s, UCG was considered to be largely technically proven, but unfortunately that coincided with the start of the era of low-cost natural gas. Consequently, interest in UCG diminished and much of the development activity stalled except in China and also in Europe, where UCG came to be seen as an alternative to mining in respect of deeper, thinner coal seams. Between 1992 and 1998, trials were carried out at depths in excess of 500 m by a European consortium (UK, Spain and Belgium) on a site at Teruel in Spain (DTI 1999). These trials demonstrated the efficacy of a new technology termed ‘CRIP’ (controlled retractable injection point) in which the nozzle releasing the steam and oxygen into the coal is gradually drawn back out of a horizontal stretch of borehole as the coal surrounding it is gasified. The trials demonstrated that UCG in deep seams is feasible with minimal environmental impact at surface level. They also found that the gas produced had a calorific value similar to that achievable with surface-level gasification of coal, and showed that, at the higher operating pressure involved, there were significant volumes of methane produced in addition to the normal syngas components. Following on from these trials, a review of the feasibility of UCG in the UK was carried out, leading to proposals for a trial under the Firth of Forth in Scotland (DTI 2006).

The costs of performing UCG using a CRIP are dominated by the costs of geological exploration and drilling. However, parallel developments in the oil and gas industry over the last few decades have led to the opportunity to use effective forms of directional drilling (first used in the Spanish trial) to access coal for UCG. Many countries with indigenous coal resources are now re-examining the opportunities offered by UCG, including South Africa and Australia. The driving forces include security of energy supply, the cost of syngas relative to natural gas and crude oil, and the option of using the syngas for power generation in a combined-cycle power plant.

To date there are no examples of integrated UCG–CCS projects being constructed anywhere in the world. This is because storage of CO_2 as a supercritical fluid (i.e. a fluid with the density of a liquid but the compressibility, viscosity and diffusivity of a gas) requires depths of at least 750 m (and probably more than 800 m for impure CO_2 recovered from flue gas), whereas UCG projects around the world to date have targeted coal seams which are shallower than this ($\leq$600 m).

The UCG process

UCG involves gasifying coal *in situ* by means of directionally drilled wells, using drilling technology developed by the oil and gas industry. The sequence of events involved in UCG is shown in Figure 1. Gasification means ‘partial oxidation’, and in the case of coal, about 80% of the original calorific value of the solid coal will be present in the resultant gas. Gasification is achieved by an exothermic reaction, which is initiated by reaction with hot steam and oxygen introduced via injection boreholes. As the operator controls the availability of oxygen, so the degree of oxidation is under the operator’s control. The resultant hot gas mixture – known as synthesis gas or ‘syngas’ – contains hydrogen, methane and carbon monoxide, all of which have significant calorific value. Depending on precise gasification conditions, varying proportions of CO_2 and hydrogen sulphide may also be present in the syngas, although hydrogen sulphide is mobilized to a far lesser degree than in conventional coal combustion (NCC 2008). The precise proportions of the various component gases in any particular syngas mixture is a function of depth (since gasification is more efficient at high pressure), oxygen injection rate and coal seam quality. Examples of typical UCG syngas compositions from a variety of coals are reported by Galli *et al.* (1983), Pirard *et al.* (2000), Perkins & Sahajwalla (2006), Khadse *et al.* (2007) and Yang (2008). These sources reveal component gas fractions in the following ranges:

- H_2, 11–35%;
- CO, 2–16%;
- CH_4, 1–8%;
- CO_2, 12–28%;
- H_2S, 0.03–3.5%.

The syngas is drawn to the surface via neighbouring production boreholes, whence it can be transported by pipeline for use in a wide range of applications, such as driving turbines to generate electricity or for manufacturing products ranging from plastics to gas and liquid transport fuels. Pre- and/or post-combustion cleanup to minimize emissions of SO_x and NO_x is typically not required for UCG applications, due to the paucity of H_2S and NH_3 in the raw syngas (NH_3 is usually entirely absent because of the strongly exothermic nature of the nitrogen oxidation reaction, which at high temperatures and pressures favours the persistence of nitrogen gas). Gaseous emissions of toxic metals are also generally negligible, as the ash present in the coal remains below ground, and largely avoids fusion (NCC 2008). Given that most UCG processes are oxygen fuelled, CO_2 and water vapour are the only gaseous exhaust streams produced after gasification, thus making separation and capture of the CO_2 relatively simple and cheap. The process is, therefore, particularly compatible with CCS.

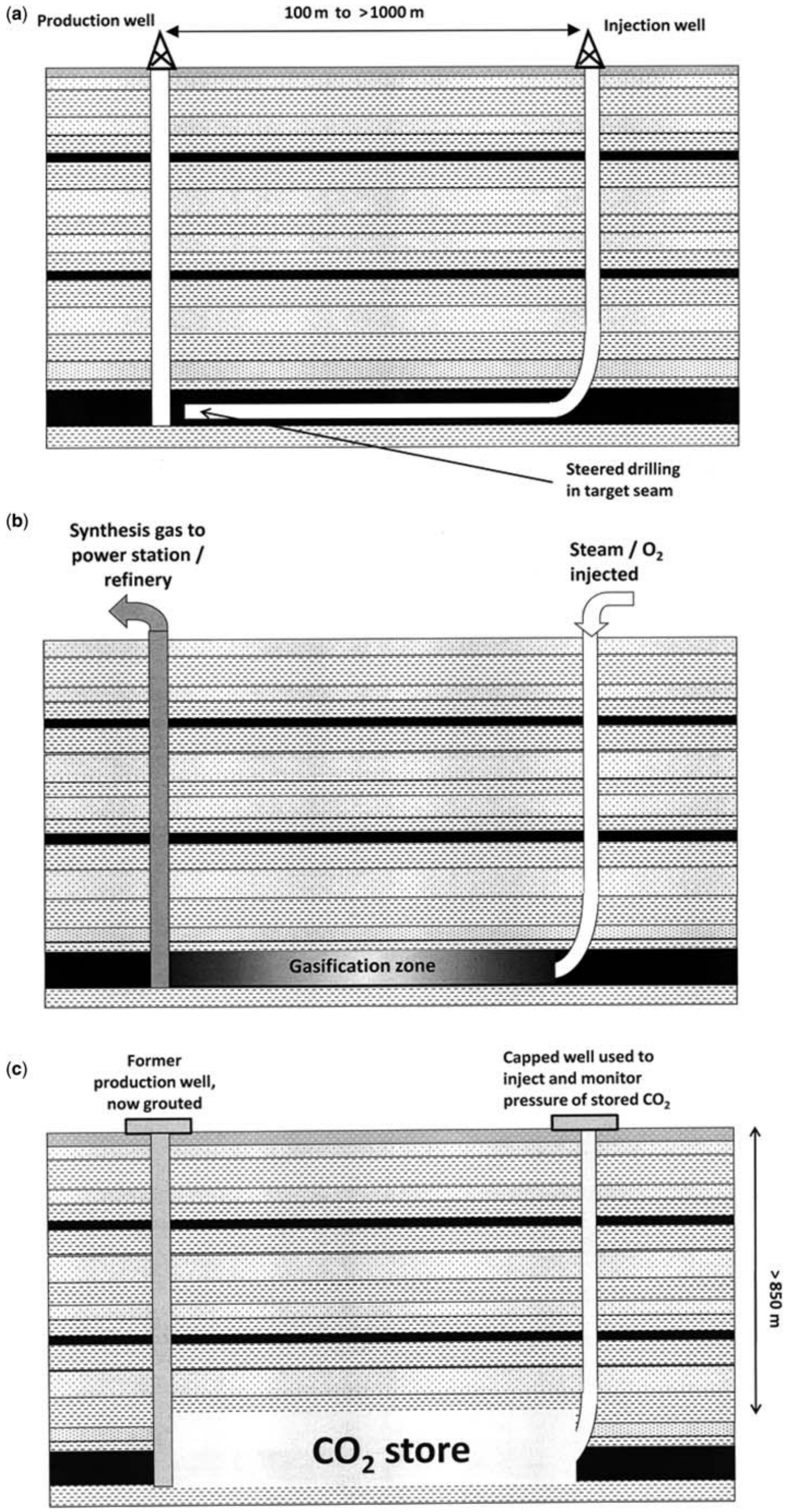

Fig. 1. Three stages in UCG–CCS. (**a**) Directional drilling of injection and production wells; the two wells do not coalesce, but a small pillar of coal is left between them which is amongst the first coal to gasify. (**b**) Creation of void by gasification to produce syngas; the gasification zone develops from left to right, progressively consuming coal closer and closer to the injection well as the controlled injection point is retracted from the end of the lateral bore. (**c**) Sealing of injected CO_2 in goaf produced by collapse of void in former gasification zone.

Prospects for CO_2 storage in UCG goaf

The UCG process creates voids deep underground following gasification of the coal. These voids will inevitably collapse, just as voids produced by longwall coal mining do, leaving high-permeability zones of artificial breccias – known as 'goaf' (from the Welsh word *ogof*, meaning a cave) – which are almost invariably isolated from the surface by low-permeability superincumbent strata (Younger *et al.* 2002). Where UCG has taken place at depths in excess of about 700–800 m, storage of CO_2 in these artificial high-permeability zones is a very attractive proposition. A combined UCG–CCS project could achieve a reduction in CO_2 emissions of as much as 85% compared with conventional coal-fired power generation. Such a project therefore offers a very attractive solution and is the only process yet devised that offers integrated energy recovery from coal and storage of CO_2 at the same site. In principle, UCG–CCS can also sit happily alongside some other CCS approaches: where CO_2 collection and transmission pipelines can be linked together, new degrees of freedom for carbon management emerge (Roddy 2008).

Subsurface injection of gases is being successfully accomplished worldwide for different purposes and in different scenarios. This includes oil and gas operations, temporary storage and permanent disposal. As some examples of this, since the 1970s, the oil industry has been practising enhanced oil recovery (EOR), which involves the injection of CO_2 into the oil reservoir, and more recently enhanced gas recovery (EGR) for gas reservoirs, including coalbed methane systems (e.g. Ross *et al.* 2009). For almost 100 years natural gas storage in salt caverns has been practised to allow supply flexibility against a fluctuating demand, and acid gas has been injected underground since the 1990s as waste in Canada.

With regard to CO_2 geological sequestration, the Intergovernmental Panel on Climate Change (Metz *et al.* 2005) proposed the following main scenarios for underground storage of CO_2: active and depleted oil and gas fields, deep saline aquifers, deep unmineable coal seams and (marginally) caverns or basalts. Based on the expected storage capacity and current experience, most of the efforts in research and all of the commercial-scale operations have been directed to storage in oil and gas operations, depleted hydrocarbon fields and associated deep saline aquifers. That is the case with Sleipner, Weyburn, In-Salah and more recently, Snohvit. Their individual annual injection rates are in a range of $0.7–2 \times 10^6$ tonnes of CO_2 and their total storage will amount to $17–20 \times 10^6$ tonnes of CO_2 each. Injection into deep unmineable coal seams has been tested in laboratory and field, with disparate results. The Recopol project in Poland found major problems in the injection of the CO_2 due to the plasticization and swelling of coal when the CO_2 is adsorbed in the coal matrix and displaces the methane. However, one option that has not been widely considered yet and could be of great interest due to a combination of economic and technical aspects is the storage of the CO_2 in the voids created by UCG.

The prospects for carbon sequestration in a UCG operation arise from a serendipitous association of a source of CO_2 and a viable long-term storage site. As with the other major CCS options, UCG–CCS takes place in a sedimentary basin with specific geological features that are particularly appropriate for geological storage. The general requirements of a site for carbon geological storage are (Metz *et al.* 2005):

- proximity to a source of CO_2, to guarantee the supply of CO_2 and improve the economics of the operation by avoiding long transportation routes;
- injectivity – the formation needs a high enough permeability to allow the injection of the fluid;
- storage capacity – sufficient to store the CO_2 produced during the plant lifetime;
- containment – some trapping mechanism has to guarantee the permanence of the CO_2 store for a considerable amount of time, *c.* 1000 years.

In addition to the generic site requirements, it is important to note the effect of the characteristics of the CO_2 stream in the constraints set on the storage site. The first of the four requirements is fully achieved by the UCG–CCS configuration. The plant and CO_2 injection infrastructures, geological and geophysical studies will have already been developed for the UCG operation when the time comes for CCS. Although capture is the main component of the cost of CCS (70–80%), the cost reduction in the remaining 20–30% is very significant.

For the other three requirements, extensive experience and knowledge in underground coal mining, especially caving methods of mining (longwall and its derivatives), provides the insights for the assessment and preliminary prediction of CO_2 storage capability. In a longwall panel, all of the coal is progressively removed from a rectangular area, and the roof is allowed to collapse, forming goaf. Typical longwall panels are usually about 1 km long, 150–250 m wide and 1–3 m high. Although there are different possible layouts for a UCG operation, one configuration is a chamber with a length of 500–600 m, 30–40 m wide and with the height equal to the thickness of the coal seam. A longitudinal pillar would separate the gasification chambers. A gasification chamber of the above dimensions corresponds to the 'shortwall' variant of collapse-based coal mining, a configuration which is well understood, as it is widely used in conventional mining to achieve rapid face movement with minimal disturbance of overlying aquifers.

Regarding the second requirement, injectivity, the absolute rock permeability is the most significant parameter to consider, the injection pressure is the second most significant parameter, and porosity is not as relevant. Thus, the injected amount varies almost linearly with permeability, while a 20% increase in injection pressure results in a 50% increase in injected CO_2 and a 100% increase in porosity shows only a 7% increase in injected CO_2. It is also important to note that the existence of a high-permeability area (or 'sweet zone') close to the injection point and a high contrast with the regional permeability acts as an enhancing factor for injectivity (Law & Bachu 1996).

Permeability changes in the surrounding strata of underground coal mining operations have been thoroughly studied in the past to inform engineering design for safe operations which avoid inducing large water inflows or gas outbursts (e.g. Younger *et al.* 2002; Esterhuizen & Karacan 2005). The process of goaf formation behind a longwall shearer track induces the formation of four distinct 'layers' above the cavity (Younger & Adams 1999):

- A caved zone, with broken blocks that have come off the roof – this is the broken material referred to as 'goaf'. The zone extends vertically to between three and six times the coal seam thickness. The final permeability of this zone will depend on the grade of re-compaction of the goaf. In the case of longitudinal pillars along the cavity, these would help to decrease the compaction, resulting in a higher permeability of the goaf. Direct measurements of saturated goaf are rather rare, but reported values are in the range of 1–20 Da (Younger *et al.* 2002), while values inferred from the hydrological behaviour of large systems of flooded panels range up to several hundred Da.
- A fractured zone with continuous fractures, joint opening and low stress. It extends to between 15 and 60 times the extraction height. Water and gas can drain directly to the void, as

Table 1. Comparison of typical permeabilities (in Da) of oil/gas reservoirs (and thus of deep saline aquifers) (after Levorsen 1967) and goaf formed by total collapse of extracted voids in coal (from literature sources and modelling results collated by Younger & Adams 1999)

Permeabilities (Da) of oil and gas reservoirs (and of deep saline aquifers)		Permeabilities (Da) of goaf from longwall mining (analogues for those formed by UCG)	
Poor reservoir	0.001–0.01	With mudstone roof strata	1–10
Good reservoir	0.01–0.1	With thinly interbedded silt–sand–mud–stone roof strata	10–50
Excellent reservoir	0.1–1	With strong sandstone/limestone roof strata	20–500

permeability in this zone can be up to 40 times the original permeability.

- A bending zone where horizontal bed separation and joint opening takes place, increasing horizontal hydraulic conductivity. This can extend to 60 m ahead of the longwall face.
- A zone of intact rock, often subject to compression beneath a final carapace of mildly extensionally disturbed rock, at or below the ground surface.

In longwall mining under the North Sea, changes in permeability of three orders of magnitude due to mining have been reported in the fractured zones above goaf (Neate & Whittaker 1979). The usual figures assumed are an increase of 100 mDa in vertical permeability and 50 mDa in horizontal. Predictions with improved modelling techniques show increases of up to 35 times in vertical permeability and 1000–2000 in horizontal permeability up to 50 m above the mining void (Guo *et al.* 2009).

In contrast, the permeabilities of oil and gas reservoirs (and thus of deep saline aquifers generally) have long been known to range from about 0.001 up to 1 Da (Levorsen 1967). As summarized in Table 1, UCG goaf and the relaxed roof strata above this will typically have permeabilities one to three orders of magnitude greater than the high end of this range. Therefore, it can be concluded that the UCG goaf and the zones of enhanced permeability above them represent a highly attractive prospect for CO_2 injection. UCG voids can be expected to cool rapidly due to goaf formation and groundwater ingress, so that even rapid subsequent CO_2 injection would be into pre-quenched zones. However, there are still some gaps in knowledge on the thermal effects on the overlying strata of the cavity, the presence of ashes and coal which can swell, and the effect of the injection pressure if it takes place before collapse.

The third requirement to consider is the storage capacity. Obviously, a remarkable advantage of UCG is the creation of a void that was not previously present. However, a rough estimation shows that the volume needed at 800 m depth to store the CO_2 produced from the syngas can be four or five times the volume occupied by the extracted coal. As with depleted hydrocarbon fields and deep saline aquifers, the storage capacity will depend on the specific storage, that is, the compressibility of the strata without exceeding the fracturing limit of the rock. Regulations for subsurface injection of waste gases in Alberta set the injection pressure limit at 90% of the rock fracturing pressure (Law & Bachu 1996).

The last requirement of a site for CO_2 geological sequestration is that it can provide containment for a considerable period of (say) 1000 years. The trapping mechanisms have been described in detail for deep saline aquifers and depleted hydrocarbon fields (Hitchon *et al.* 1999; Metz *et al.* 2005; Bradshaw *et al.* 2007). First of all a caprock is required which acts as a structural seal for the buoyant supercritical CO_2. Then, with increasing temporal and spatial scale, the rest of the mechanisms start to work: hydrodynamic trapping, residual gas dissolution in formation water and mineral precipitation. All these processes will occur according to the physical and chemical characteristics of the site and the CO_2 stream. In addition, in the case of UCG, the organic and inorganic by-products will certainly be mobilized with the CO_2 due to its solvent power, which is a key consideration in planning to avoid any pollution of adjoining aquifers in the event of contaminant migration. This will affect the chemical reactions in the water and the rock. It is also possible that the CO_2 is adsorbed in the coal matrix due to its higher affinity compared with other elements. In such a case, any resulting methane emissions would need to be factored into the overall greenhouse gas sequestration calculation.

As with permeability issues, the experience of underground coal mining is helpful in the quantification of containment in a coal basin. For more than a century, underground coal mining has been carried out under the sea in NE England using longwall methods, with workings extending as far as 14 km from shore; yet no incident of sea water in-rush ever occurred (Bičer 1987). Coal mining regulations in Britain state that the minimum distance from the seabed to mine works is 105 m, 60 m of which has to be within Coal Measures strata. Given that the viscosity of water is higher than that of supercritical CO_2, further comfort might be sought. In a more closely analogous case, Whittles *et al.* (2006) simulated the leakage of methane (with a viscosity of 1.75×10^{-5} Ns m^{-2}) into the mine workings in a UK colliery. They found that potential sources beyond 20 m of the working face would not leak into the roadway due to the reduced permeability resulting from increased confining stress.

In conclusion, it can be expected that the trapping mechanisms described in the literature will work in the case of UCG, and that specific sites which meet the requirements can provide the necessary confinement. However, caution has to be exercised, as there is no experience of the large scale that CO_2 storage would imply. The cumulative effects of multiseam extraction could also be important.

Another critical aspect which influences the mechanisms and requirements for the CO_2 storage site is the characteristic of the CO_2 stream to be injected. Anthropogenic CO_2 contains impurities which depend on the combustion process and the capture method. Some of these impurities are H_2O, SO_2, NO, H_2S, O_2, CH_4, HCN, Ar, N_2, H_2 and particulates (Anheden *et al.* 2005) and they will affect the thermodynamics (density, viscosity, critical point) compared with pure CO_2 (Li *et al.* 2009). In general, the presence of impurities decreases the critical temperature and increases the critical pressure (Seevam *et al.* 2008) at which CO_2 enters its supercritical state – which is essential for geological storage without further reaction. A stream emanating from a post-combustion process shows the smallest difference compared with pure CO_2, but in the case of pre-combustion or oxyfuel processes, the supercritical pressure can reach 83 or 93 bar while the critical temperature decreases to 29 or 27 °C respectively (Seevam *et al.* 2008). For typical northern Europe conditions, this would imply minimum depths in the order of 800 m for CCS to work (it could be deeper than 900 m if an oxyfuel combustion flue gas is to be stored).

Remaining technical challenges for UCG–CCS implementation

UCG–CCS faces the same challenges as any other comparable industrial operation, in relation to issues such as pollution prevention (e.g. WS Atkins Consultants Ltd 2004; Liu *et al.* 2007), landscape protection, nature conservation, etc. As UCG involves total extraction of coal in certain areas, it has the potential to induce land subsidence in a manner similar to longwall coal mining, albeit at the depths appropriate for UCG–CCS, surface lowering would be barely detectable. Long-established procedures for dealing with coal mining subsidence (e.g. NCB 1975) can be readily transferred across to UCG–CCS operations.

Nevertheless, a number of open questions remain, which will only be settled as UCG–CCS is more widely implemented at full scale and refined in the light of experience. These include the following issues:

- optimal layouts for injection and production boreholes, and strategies for managing simultaneous multiple-seam UCG–CCS development;
- borehole integrity, especially in view of the extremes of heat which are experienced by production boreholes, and the extremes of chilling which can be expected during CO_2 injection;
- the feasibility of adapting existing offshore platform technology to accommodate the full range of high-temperature operations required for UCG–CCS implementation;
- lack of precise process control in comparison to conventional (surface) gasifiers – it is not possible to fully predict or control rates of groundwater ingress, heterogeneity in reactant availability within gasification zones, or the precise limits and rates of expansion of voids and the concomitant formation of goaf and, because of this, and because of the lack of any equivalent of stockpiling fuel, it is difficult to get UCG to proceed as a steady-state process (in terms of both gas yields and heating values) unless a large number of auxiliary boreholes are installed (cf. NCC 2008);
- the response of strata to coal removal under non-isothermal conditions – in conventional coal mining, thermal effects can be ignored in geomechanical modelling, but it is unlikely that this approach will remain valid in situations of extreme temperature gradients as expected during UCG.

Active research on all of these topics is currently under way at a number of centres worldwide, and early indications are that all of these difficulties are surmountable.

The economic case for UCG–CCS

As with all commodities, the economic case for UCG–CCS amounts to a balance of credits and debits. On the credit side, UCG–CCS offers a low-cost route to emissions reduction; the cost is lower than for surface gasification plants because there is no need to mine, store or transport coal, there are no solid residues to dispose of, and there is no need to purchase a gasifier; it converts an abundant natural resource into a secure, economic supply of gas; it enables stranded coal resources (e.g. deep or offshore) to be converted into commercial reserves; there is a range of potential end uses and markets, for example, power generation, heating, synthetic fuels, chemicals and hydrogen; it is largely immune to crude oil price swings (unlike conventional coal mining which relies on diesel-fuelled equipment and transportation); it is cheaper than natural gas for power generation; and finally, as has been explained in greater detail above, UCG creates conditions for deep geological storage of CO_2 which are orders of magnitude more favourable than natural saline aquifers or depleted hydrocarbon reservoirs.

On the debit side of the balance sheet for UCG–CCS are: technical and commercial uncertainties (e.g. lack of economies of scale) since the technology has not yet been widely deployed; syngas production rates and composition are variable compared with pipeline-delivered natural gas; open-cast coal mining (where acceptable) is cheaper; ground subsidence must be managed, and there is some risk of aquifer contamination; trials and prospective site evaluation are expensive; there can be significant costs in transporting the syngas to the point of use; carbon capture technology for high-temperature pre-combustion applications is not yet a commercial reality (though capture post-combustion is); and planning approval processes (not only for UCG but also for CCS) are still under development in the majority of countries.

Wide-scale proliferation of commercial UCG projects has thus far been inhibited by the availability of comparatively cheap supplies of crude oil and natural gas. Looking at 2008 data, against a natural gas price (in the USA) of \$9 per million Btu, raw syngas can be produced via UCG in the onshore USA for \$1.8 per million Btu based on air gasification (Green 2008). Using oxygen-blown UCG in onshore Europe, the cost of syngas becomes \$3.8 per million Btu. These figures are now sufficiently low for UCG to look commercially attractive whenever oil and gas prices are reasonably high.

The economic case for UCG syngas displacing natural gas or coal for power generation is relatively straightforward. Alternative uses such as conversion of syngas into liquid fuels, chemical intermediates or hydrogen are more difficult because, whilst the added value is well known (and much higher than for power generation), there is a tighter requirement for syngas cleanup. Technologies for cleaning up UCG syngas to chemical feedstock standard are still under development and so the costs are less well known. There are several such projects under way at present, which should help elucidate the figures in due course.

Other factors beyond straight economics then come into play to tip the balance. The main considerations are: CO_2 emissions and climate change; air quality and power station emissions; a desire for some protection against volatile and rising oil and gas prices; and considerations of national energy and fuel security in a politically unstable world – after all, the distribution of coal around the world is different from the distribution of oil and gas.

There is an additional factor to consider – and one that is difficult to place a value on in economic terms. More than 5000 deaths a year occur in the coal mines of China: four deaths for every million tonnes of coal mined. In Ukraine, the death rate is even worse: seven deaths per million tonnes. To put these figures into perspective, the last time death rates in UK coal mines were as high as they currently are in China was back in the 1920s; in the case of Ukraine the parallel figures occur way back in the 1880s. Much of this mining is linked to energy provision in support of the manufacture of goods for export to Western countries. UCG could provide an ethically acceptable way of enabling this economically driven low-cost manufacturing activity to continue.

Approaches to environmental risk assessment for UCG–CCS

An Environmental Risk Assessment (ERA) should answer four questions: what can occur that causes adverse consequences; what is the probability of occurrence of these consequences; how severe can they be; and how can they be reduced? This last issue is often referred to as risk management, though it differs from the more general risk management which takes into account economic and social considerations. The steps in performing an ERA to address these questions are:

- hazard identification, to reveal the contaminants and adverse situations that can be expected;
- exposure assessment, to describe the intensity, frequency and duration of exposure, routes of exposure and the nature of the population exposed;
- effect assessment, to describe the response of the receptors;
- risk characterization, to provide an estimate of the likelihood for adverse impacts, with endpoints definition and a qualitative or quantitative approach;
- risk management, which includes monitoring and mitigation options.

The ERA is a critical aspect in the development of both UCG and CCS and so far the two processes have been addressed separately. However, they share substantial common ground. Usually, when the ERAs are undertaken for UCG and for CCS, each is split into surface operations and what happens underground. The handling of gases like syngas from UCG or CO_2 is common practice in industry, and environmental, health and safety and other standards and regulations are well established. Also the engineering design is controlled, resulting in low failure rates. For example, CO_2 pipeline failures in the USA in the period of 1990–2001 had a frequency of 3.2×10^{-4} incidents per kilometre per year and the frequency of oil well blowouts in the Gulf of Mexico and the North Sea was of 10^{-4} incidents per well per year (IEA 2004). However, when it comes to the underground dimension, lack of previous experience and large uncertainties in geology and in hydrogeological, chemical and geomechanical behaviour appear.

The environmental risks associated with UCG were one of the reasons why UCG was not further developed in the 1970s and 1980s in the USA. Despite its indisputable benefits, initial trials at shallow depth (less than 200 m below surface), which produced groundwater contamination and even severe surface subsidence (as in Hoe Creek), discouraged pursuit of new experiments. Nevertheless, more recent projects (like Chinchilla in Australia) have proved that with good site selection and operation control, groundwater contamination can be avoided.

The main risks to be considered in UCG are groundwater depletion, groundwater contamination, gas leakage and subsidence. Set against these, its environmental advantages compared with conventional coal mining and surface combustion include the elimination of coal transport, stockpiles and much of the disturbance at surface, low dust and noise levels, the absence of health and safety concerns relating to underground workers, the avoidance of ash handling at power stations, and the virtual elimination of SO_x and NO_x emissions. Most of the contaminants produced in coal gasification are included in List I of the Water Framework Directive (2000/60/EC), which forbids release into a water body. Consequently, for a UCG operation to be permitted in the EU, any potential water contamination would almost certainly have to be restricted to water which had been previously classified as Permanently Unusable. The potential contaminants have been described and are well known (Humenick & Mattox 1978; Liu *et al.* 2007). They include organic compounds (phenols, benzene, PAHs and heterocyclics) and inorganics (calcium, sodium, sulphate, bicarbonate, aluminium, arsenic, boron, iron, zinc, selenium, hydroxide and uranium).

The approach that is proposed for environmental assessment of UCG is a risk-based approach with a source–pathway–receptor scheme (WS Atkins Consultants 2004). For CO_2 storage, the main risks identified are divided into three groups (Chadwick *et al.* 2008): leakage, dissolution in formation water and displacement. At a local scale, leakage into the atmosphere or the shallow subsurface can cause asphyxiation to animals or humans, or affect plants and underground ecosystems. If the leakage is offshore, it can affect the living organisms in the water column and the seabed and interfere with other legitimate uses of the sea. It is also important to make a distinction between sudden large releases and continuous small ones. Large releases from the storage site, however, are not expected unless there is a secondary accumulation close to the surface. The CO_2 injection could also initiate the mobilization of methane which is potentially explosive. On a global scale, the leakage of CO_2 or methane would hinder the ultimate aim of the sequestration, which is to reduce the concentration of greenhouse gases in the atmosphere. If a leak contains some other contaminants, they can pose an additional threat if exposure times and concentrations are toxic or carcinogenic. Regarding the risks resulting from dissolution in other fluids, the variation in pH of water caused by CO_2 can lead to the mobilization of metals. As CO_2 is a very good solvent, it can also transport other organic contaminants and contaminate potable water. The displacement of the CO_2 plume can induce seismicity or ground heave or subsidence. The brines pushed away can contact and contaminate potable aquifers or damage other mineral or energetic resources. It is also important to note that, although a single specific site should not pose a high risk, there is a cumulative effect as the number of storage sites increases in response to the large-scale opportunity for global warming mitigation.

The coupling of UCG–CCS alters the hazards and the risks inherent in UCG or CCS on its own (Burton 2007). On the one hand, the operation takes place at a much greater depth than conventional UCG (so that the conditions for CO_2 in its supercritical state are met). This certainly decreases the risk of potable aquifer contamination and of subsidence effects on the surface. In addition, the physical response of the surrounding coal to the CO_2 injection can help reduce the migration pathways by swelling. On the other hand, the pressurization of the cavity with the injection of the CO_2 can increase the risk of fracture propagation. Under these circumstances, the organic and inorganic by-products of gasification are forced out of the reaction chamber as the CO_2 is injected and pressurized in the void. The transport of organic and inorganic contaminants dissolved in the CO_2 through a fractured and porous medium is an area that has not been studied yet. Their concentration in the CO_2 plume and the changes in flow and chemical reactions between the CO_2, tars, ash, coal, brine and the formation rocks are unknown.

Although it is desirable to have a quantitative risk assessment, this has not always been possible in the ERAs performed for CO_2 storage projects. The reason for this is the lack of available data at this stage. Consequently, some studies have been performed using a deterministic analysis based on well proven numerical simulation tools and examining different scenarios (Espie *et al.* 2005). There have been various projects around the world to perform the ERA of CO_2 geological storage using several methodologies to characterize risk (Damen *et al.* 2006). From these projects, it seems likely that the most effective approach for UCG–CCS risk characterization in the future will have to combine deterministic numerical models with probabilistic analysis. These models will have to be able to couple thermal, geomechanical, transport and chemical processes.

Monitoring is especially important at the local scale, to be able to detect and mitigate any threat to safety. On a global scale, monitoring is important for dealing with issues related to credits for emissions reduction. Monitoring of the UCG operation is based on measurement of temperature, pressure and mass balance, as well as water chemistry and water level in monitoring wells. In the CO_2 injection phase, CO_2 stream injection rates, composition, temperature and pressure have to be monitored. The migration of the CO_2 can be checked with periodic sampling of air, water and soil, with pressure and logs in wells, with CO_2 flux chambers or using eddy covariance and indirect techniques such as geophysics or remote sensing. Since sealed wells represent the preferential pathway for leakage, their integrity has to be assured. That can be done with cement bond logs (Metz *et al.* 2005; Burton 2007; Chadwick *et al.* 2008). The mitigation options in the event of leakage are: recapping of leaking wells, reducing injection pressure, stopping injection, sealing the fracture or transferring the CO_2 (Anonymous 2006).

Northeast England case study

Despite the long history of industrial coal mining in the region (starting in 1585), huge reserves of coal remain in NE England. Only about 25% of the total coal resources have been extracted. There is coal in abandoned mines that is technically mineable – perhaps in excess of 500×10^6 tonnes. Some of this coal lies under land: most under the sea. However, because the mines have not been maintained there would be expensive problems to overcome. Typically it is found that roadways deteriorate, and electrical and mechanical equipment is destroyed as a result of flooding once water pumping operations cease. There is also the possibility of trapped water leading to sudden in-rushes, which would present a risk to personnel in the event of underground mining being re-established (Younger *et al.* 2002).

Then there is the coal that lies at depths considered uneconomic for conventional mining – both under the land and under the sea. This is particularly attractive for UCG when linked to CCS for the reasons given above, and could easily exceed another 500×10^6 tonnes. Previous estimates for the UK have suggested that between 7 and 16×10^9 tonnes of coal suitable for UCG could be available – and that ignores all coal below a depth of 1200 m (Green 2008).

Project Ramsay (named after Sir William Ramsay) was established to assess the opportunity for UCG–CCS in NE England. As part of the project, specialists were commissioned to undertake a thorough review of all available data to determine the quantity and accessibility of coal suitable for UCG and for UCG–CCS in nearshore areas of the NE coast. The study examined available data from a number of sources including the Coal Authority, the British Geological Survey and BERR as well as data held by others, including Newcastle University.

Suitability of the area was considered for UCG and UCG–CCS taking into account coal seam thickness, depth of cover between the top of target coal seams and the seabed where relevant, permeability of the pertinent strata and, where relevant, stand-off distances from old workings. For UCG a depth of 100 m or greater was used, and for UCG–CCS the minimum depth was increased to 800 m to achieve the storage pressures necessary for CO_2 in its supercritical state.

The project considered both nearshore coal seams (<2 km) and offshore coal seams (up to 10 km) at a few locations. The primary difference in approach between nearshore areas and further offshore is in the ability to reach the coal reserves from a wholly shore-based enterprise using directional drilling v. the need to utilize offshore rigs. Cost analysis has shown that there is not a significant cost advantage in one approach over the other for the coal reserves under consideration. The initial high cost of offshore rigs is broadly offset by the more expensive long-reach drilling costs associated with a nearshore project. The project found some very interesting coal seams and concluded that previous estimates of UCG-compatible coal resource had been conservative.

However, generating syngas from coal is only part of Project Ramsay: the region also provides ready energy and chemicals markets for syngas and its derivatives, and therefore offers a genuine prospect for a commercial UCG–CCS operation. Geography is important: these markets need to be sufficiently close to the chosen UCG base to be serviceable economically. The siting of a UCG production operation in NE England allows ready access to the process industry markets on Teesside for syngas and for derived gas products of methane and hydrogen. Equally, there are a number of existing power users and potential new investments in power generation plant at a scale that could make syngas a viable fuel. These options were all reviewed as part of the feasibility study.

From its inception, Project Ramsay always considered CCS as being an essential element of a successful UCG project. Consequently, detailed consideration has been given to those coal targets that are at sufficient depth to provide the option for CO_2 storage and where significant revenues can be generated by providing a long-term storage site for CO_2. Note, however, that CO_2 is also generated in large quantities by the same process and power industries that provide a potential market for the syngas and its derivatives. Increasingly there is a business opportunity in CO_2 collection, transmission and storage. There is therefore the option of extending the envelope to take in CO_2 from other industrial sources and offer additional storage capacity. The voids created through the UCG process in deep coal seams provide a storage option for CO_2 whether that CO_2 was produced through use of UCG syngas or from other industrial activities.

The study took account of specific local factors such as: the location of the most suitable coal seams relative to existing power plants and potential new power plants; the existence of pipeline corridors; the location of the most suitable coal seams relative to large industrial users of syngas and hydrogen; the potential for linking into other sources of CO_2 and CO_2 collection systems; the potential for connecting the UCG facility to the proposed new CO_2 pipeline linking the Eston Grange IGCC/CCS plant to storage locations under the North Sea, and so on.

The broad conclusions were that: previous estimates for UCG-compatible coal had been conservative; there are coal seams that appear to be usable for CO_2 storage following UCG; and some of the end uses for syngas are potentially attractive. The most attractive options in financial terms are (1) to sell syngas, take back captured CO_2 and store it for a fee, and (2) to sell decarbonized hydrogen and methane. It was concluded that a project could be done in three phases, ramping up the scale over time in order to minimize technical risk and investor exposure. Such a project could deliver a profit before year 10 and therefore might warrant follow-on discussion on a more commercial basis with interested parties. If developed on a broader scale, it could act as a source of investment funds for the renewable energy sector and thereby go beyond the ambition of being a bridging technology on the road to a sustainable energy future.

Conclusion

Estimates of the total global coal resource are in the order of thousands of billions of tonnes, whereas figures usually quoted for accessible coal reserves are typically tens of billions of tonnes. There is thus a huge gap between reserves and resources. UCG offers the tantalizing prospect of closing that gap quite considerably. If the UCG opportunity can be linked successfully to emerging CCS technology, then the implications for addressing the twin challenges of climate change and finite fossil fuel reserves is truly game-changing. There are particular attractions in developing a ‘self-contained’ solution whereby clean use of coal and CO_2 sequestration are combined in the same location without a need for material transfer. From a different perspective, there is an attraction in extending the envelope to include syngas export and CO_2 import/export. The former opens up the prospect of linking into lucrative opportunities beyond the power generation sector: the latter offers contingency plans on a number of fronts. The main environmental challenges lie in guarding against (1) aquifer contamination which can impact on potable water supplies and (2) land subsidence. Well established techniques exist for dealing with both of these. The main economic challenges relate to the up-front costs associated with evaluating specific sites from a commercial perspective and from an environmental perspective, largely because of the drilling costs associated with characterizing deep coal seams. The pace is tending to be set by those countries and regions that are blessed with significant coal resources and are concerned about the greenhouse gas emissions agenda.

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