

Storage capacity and containment issues for carbon dioxide capture and geological storage on the UK Continental Shelf

S. Holloway

British Geological Survey, Keyworth, Nottingham, NG12 5GG, UK

Abstract

CO₂ can be stored in geological formations beneath the UK Continental Shelf as a greenhouse gas mitigation option. It can be trapped in subsurface reservoirs in structural or stratigraphic traps beneath cap rocks, as a residual CO₂ saturation in pore spaces along the CO₂ migration path within the reservoir rock, by dissolution into the native pore fluid (most commonly brine), by reaction of acidified groundwaters with mineral components of the reservoir rock, or by adsorption onto surfaces within the reservoir rock, e.g. onto the carbonaceous macerals that are the principal components of coal. Estimates of the CO₂ storage capacity of oil and gas fields on the UKCS suggest that they could store between 1200 and 3500 x 10⁶ tonnes of CO₂ and up to 6100 x 10⁶ tonnes CO₂ respectively. Estimating the regional CO₂ storage potential of saline water-bearing sedimentary rocks is resource-intensive and no UK estimates have yet taken into account all the factors that should be considered. Existing studies estimate the pore volume and likely CO₂ saturation in the closed structures in a potential reservoir formation but do not take account of the potentially limiting regional pressure rise likely to occur as a result of the very large-scale CO₂ injection that would be necessary to make an impact on national emissions. There is undoubtedly great storage potential in the saline water-bearing reservoir rocks of the basins around the UK, but the real challenge for studies of aquifer CO₂ storage capacity in the UK is perhaps not to estimate the total theoretical CO₂ storage capacity, as this is not a particularly meaningful number. Rather it is to thoroughly

investigate selected reservoirs perceived to have good storage potential, to a standard where there is scientific consensus that the resulting storage capacity estimates are realistic. This will allow it to be considered as closer to the status of a reserve rather than a resource and will help define the scope for CCS in the UK.

Keywords

CO₂ storage capacity, containment, CCS, UK

1. Introduction

There are many natural underground CO₂ fields around the world [1, 2, 3]. These are identical to natural gas fields in every respect apart from their gas composition.

Furthermore many oil and natural gas fields contain varying quantities of CO₂ mixed with the hydrocarbon gases [4]. Many of these fields of both pure CO₂ and CO₂-hydrocarbon mixtures have existed for hundreds of thousands to tens of millions of years. This proves that under favourable circumstances large quantities of CO₂ can be retained underground for appropriate timescales.

Rocks suitable for CO₂ storage commonly occur in major accumulations of sedimentary rocks known as sedimentary basins that may be up to a few kilometres thick and cover thousands of square kilometres. However, although very common, sedimentary basins do not occur in every country in the world. Nor are all sedimentary basins suitable for CO₂ storage; some may not contain suitable reservoir rocks, others may not contain suitable barriers to prevent injected CO₂ migrating out of reservoir rocks.

2. Typical physical conditions for geological CO₂ storage

The average temperature in many sedimentary basins increases by about 25-35°C km⁻¹ below the ground surface or sea bed, as a result of heat flow from the inside to

the outside of the Earth. However, there is considerable variation in such geothermal gradients, both locally within basins and between basins [5]. Pressure also increases downwards within the subsurface. Pressure in the pore spaces of sedimentary rocks is commonly close to hydrostatic pressure, which is the pressure generated by a column of water (or brine) of equal height to the depth of the pore space. This is because the pore space is commonly filled with water or brine and is connected, albeit tortuously, to the ground surface. There is some variation in hydrostatic pressure gradients, caused by lateral and vertical variation in the salinity of the water filling the pore space. Under conditions where the pore space is not connected to, or not in equilibrium with the surface, pressure may be greater than hydrostatic, when it is known as overpressure. The converse, underpressure, may also exist, either naturally, or as the result of abstraction of fluids such as oil and gas from a reservoir rock.

When CO₂ is stored underground, there is a sharp increase in its density and corresponding decrease in volume at depths between approximately 600 m and 1000 m depending on the precise geothermal conditions and pressure (Figure 1). This is associated with the phase change from a gas to a dense supercritical fluid.

Consequently, CO₂ occupies much less space in the deep subsurface than at the surface. One tonne of CO₂ at a density of 700 kg m⁻³ occupies 1.43 m³, but at 0°C and 1 atmosphere one tonne of CO₂ occupies approximately 509 m³.

Under the pressure-temperature conditions commonly found in the subsurface, supercritical CO₂ is less dense than, and only slightly miscible (mixes only slightly) with, the water or brine that is most commonly found within the pore spaces and fractures in sedimentary rocks. It is fully miscible (mixes completely) with, but denser than natural gas, and can be fully miscible with oil, both of which are also buoyant

relative to water or brine. Gaseous CO₂ is considerably less dense than water or oil and fully miscible with natural gas. Supercritical CO₂ has a low viscosity.

3. Storage mechanisms

The main mechanisms that trap CO₂ in the subsurface are:

- Its buoyancy compared to water or brine, which allows it to rise through the reservoir and accumulate and be retained in structural or stratigraphic traps beneath cap rocks
- The development of a residual CO₂ saturation in pore spaces along the CO₂ migration path within the reservoir rock
- Dissolution into the native pore fluid (most commonly brine)
- Reaction of acidified pore waters with mineral components of the reservoir rock
- Adsorption onto surfaces within the reservoir rock, e.g. onto the carbonaceous macerals that are the principal components of coal

Geological storage of gaseous or supercritical CO₂ in structural or stratigraphic traps requires a combination of a porous and permeable reservoir rock that will act as the storage reservoir and a low-permeability geological barrier such as beds of mudstone or halite in a configuration that will isolate the CO₂ from the atmosphere. The efficacy of storage depends on the effectiveness of the barrier. Low-permeability barriers can be divided into two classes: *aquicludes*, which are rocks such as halite that are essentially impermeable if not fractured, and *aquitards* which are rocks such as shales and mudstones that have significant porosity but, because of their very small pore and pore throat size, have very low permeability. The porosity of aquitards is usually water-filled. If they are water-wet, i.e. water occurs as a continuous phase through the

pore system of the rock, water (including water containing dissolved CO₂) can pass through the porosity, albeit very slowly, in response to a pressure gradient. Water may also pass through both aquicludes and aquitards via fractures such as faults or joints, if these are present.

Most saline water-bearing reservoir rocks and oil and gas reservoirs are clastic and carbonate sedimentary rocks. Fluids flow through them via connected, commonly intergranular, porosity and/or fractures. CO₂ sent for storage would be injected into them via a well or wells, at sufficient pressure to displace some of the pore fluid already present in the pore spaces and fractures. However, many reservoir formations are subdivided into compartments by faults, which may prevent, inhibit or allow the transmission of fluids. If the compartments are small and the faults are sealing, or only transmit fluids when large pressure differences develop across them, there could be a rapid pore fluid pressure rise within the compartment into which injection was taking place, and the fracture pressure of the reservoir rock or cap rock could be exceeded. Thus the CO₂ storage capacity of reservoir rocks is a function not only of their intrinsic rock properties (e.g. porosity, permeability and heterogeneity) but also their size and the nature of their boundaries: a cap rock must be present above the reservoir to retain the CO₂, but at least some part of the boundary of the reservoir must be able to transmit the pore fluid displaced by the injected CO₂. Ultimately the displaced fluid would be accommodated by fluid movement to the seabed or water table and also perhaps, by a slight expansion of the geological system into which injection was taking place [6].

The rate of trapping by dissolution into brine will depend on how well the CO₂ mixes with the formation water once it is injected into the reservoir. Once a CO₂

accumulation has reached a stable position within the reservoir, diffusion of CO₂ into the water will be faster if it is a thin but widespread accumulation, with a high surface area to volume ratio. However, for many accumulations, dissolution could be slow; in the order of thousands of years for typical injection scenarios [7], unless there is some form of active mixing induced by fluid convection within the reservoir [8]. Once CO₂ has dissolved into brine, the brine becomes slightly denser than non-CO₂-saturated brine and thus has negative buoyancy. Consequently the only way it can leak to the surface is if the CO₂-saturated brine itself migrates closer to the surface (reducing the pressure and allowing some of the CO₂ to come out of solution). There is natural fluid flow in some reservoir rocks but this is commonly in the order of centimetres per year. In hydrostatically pressured reservoirs there is no pressure gradient to drive flow.

Dissolution results in acidification of the brine into which the CO₂ dissolves, which can enable chemical reactions between the acidified brine and the rock matrix or the reservoir, particularly the dissolution of carbonate minerals such as calcite and, at much slower rates, basic aluminosilicate minerals. The reaction of acidified brines with basic aluminosilicate minerals could lead to the precipitation of carbonates; so-called mineral trapping of carbon as a solid phase. However the kinetics of such reactions are very slow; time spans in the order of hundreds to thousands of years may be necessary for significant storage by this mechanism [9].

Residual saturation trapping occurs because a proportion of the injected CO₂ remains behind when a plume of injected CO₂ sweeps through the reservoir rock. This is trapped by capillary forces and in very small-scale structural or stratigraphic traps. Residual saturation may be in the order of 5-30% [7] and thus it could be an important

trapping mechanism, particularly if CO₂ is injected near the base of heterogeneous reservoir formations [10].

Coal seams can be reservoirs for gases. Coal contains a natural system of orthogonal fractures known as the cleat, which imparts some permeability to it, and although the solid coal between the cleats does not contain significant conventional porosity it contains micropores in which a natural gas known as coalbed methane (CBM) can occur. This usually consists of >90% methane plus small amounts of higher hydrocarbons and small amounts of CO₂ and N₂. The gas molecules are adsorbed onto the surfaces of the micropores. CO₂ has a greater affinity to be adsorbed onto coal than methane. Thus, if CO₂ is pumped into a coal seam, it may be stored by becoming adsorbed onto the coal, and may displace methane from the adsorption sites. Any methane recovered could have an economic value and offset some of the costs of CO₂ sequestration. Experimental injection of over 100,000 tonnes CO₂ into the Fruitland coal seams in the San Juan Basin, USA, has enhanced coalbed methane production [11]. However, coalbed methane production (and probably CO₂ injection) can only be established in a minority of coalfields with exceptional permeability. Moreover, the methane in coal represents only a small proportion of the energy value of the coal, and the remaining energy would be sterilised if the coal were used as a CO₂ storage reservoir, i.e. the coal could not be mined or gasified underground without releasing the CO₂.

It might be considered advantageous to store as much of the injected CO₂ as possible by the latter four mechanisms (residual saturation trapping, dissolution, geochemical reaction and adsorption) which effectively immobilise it over the very long term, as opposed to storing it as a mobile phase in structural and stratigraphic traps where

there is a possibility that it might leak as a result of unanticipated migration pathways through the cap rock. Strategies that decrease the mobility of the injected CO₂ are therefore desirable.

4. Storage capacity

Estimates of the availability of many geological resources such as minerals and fossil fuels are commonly divided into at least two categories: *resources* (accumulations of anything that is useful and potentially accessible to mankind) and *reserves* (that part of a resource that is available for production now, by being economically recoverable under current technological conditions).

Potential CO₂ storage space in geological formations can be considered as a resource because it is potentially useful to man. However, very little of it appears to be economically exploitable now under current technological conditions and thus qualify as a reserve: incentives such as emissions trading certificates or carbon taxes are required to make geological CO₂ storage cost-effective, except in some enhanced oil recovery projects.

Hence another means of subdividing the resource is required. It has been proposed [12, 13] that the degrees of geological and economic uncertainty associated with various parts of the resource can be considered in terms of a techno-economic resource pyramid (Figure 2).

The following categories of CO₂ storage capacity, described below in ascending order, are nested within the resource-reserves pyramid:

- 1) **Theoretical Storage Capacity** is the total resource. It encompasses the whole of the resource pyramid. It assumes that the entire capacity of the system

under consideration to store CO₂ in pore space, or dissolved at maximum saturation in formation fluids, or adsorbed at 100% saturation in the entire coal mass, is accessible and utilized to its full capacity.

- 2) **Effective Storage Capacity** represents a subset of the theoretical capacity and is obtained by considering that part of the theoretical storage capacity that can be physically accessed and which meets a basic range of geological and engineering criteria. It excludes the lowest part of the pyramid.
- 3) **Practical Storage Capacity** is that subset of the effective capacity that is obtained by considering more detailed technical criteria, plus legal, regulatory, infrastructural and general economic barriers to CO₂ geological storage. The Practical Storage Capacity corresponds approximately to the ‘reserves’ concept used in the energy and mining industries. It excludes the lowest two parts of the pyramid.
- 4) **Matched Storage Capacity** is that subset of the practical capacity that is obtained by detailed matching of large stationary CO₂ sources with geological storage sites that are adequate in terms of capacity, injectivity and supply rate to contain CO₂ streams sent for storage from that source or sources. This capacity includes only the top section of the resource pyramid.

At the apex of the pyramid are those storage sites or formations that have good geological characteristics, large storage capacity and are located close to emission sites with low costs of capture. At the base of the pyramid are the extremely difficult sites, with problematic geological conditions, and/or small storage capacity, which potentially may be located at great distance from sources with large capture costs – and, most importantly, the resources that are speculative or poorly known. At present

few assessments of potential storage sites in the UK have been made and the total potential storage capacity at the base of the pyramid is very much greater than that at the top, largely because much of the theoretical storage capacity is very poorly understood.

It is also recommended that all estimates of geological CO₂ storage capacity should (a) clearly state the limitations that existed (data, time, knowledge) at the time the assessment was made and (b) indicate the purpose and future use to which the estimates should be applied. Assessments that lack documentation of constraints (or justification for their use) cannot be easily compared with other assessments [12].

5. CO₂ storage capacity in the UK

The UK's major potential sites for the long-term geological storage of CO₂ are oil and gas fields and saline water-bearing reservoir rocks. There is thought to be only limited quantifiable CO₂ storage potential in coal seams in the UK for the following reasons:

- UK coal seams generally have low permeability, which is evident in the lack of success in establishing coalbed methane (CBM) production in the UK. Thirteen CBM wells had been drilled in 6 different projects to November 2004, and no commercial production had been established [14].
- Coal is an important energy mineral and its use for CO₂ storage would limit the potential for mining or underground gasification of the coal in the future. Because of these potential conflicts of interest, it is not considered likely that coal resources at depths above 1500 m would be allocated for CO₂ storage in the UK.

There are significant coal resources in the UK at depths below 1500 m [14]. However, their permeability is likely to be lower even than that inferred in shallower seams because of the increased lithostatic pressures at depth. Moreover, the process by which CO₂ is trapped in coal seams at temperatures above the critical point (31.1°C) is not well understood. It seems that adsorption is gradually replaced by absorption and the CO₂ diffuses or “dissolves” into the coal. Carbon dioxide is a “plasticizer” for coal, lowering the temperature required for its transition from a glassy brittle structure to a softer, rubbery, plastic structure. Indeed in one case, this transition temperature was interpreted to drop from about 400°C at 3MPa to <30°C at 5.5 MPa. Coal plasticization or softening may adversely affect any permeability that would allow CO₂ injection. Coal also swells as CO₂ is adsorbed and/or absorbed, which reduces permeability by orders of magnitude or more [15]. Some studies suggest that injected CO₂ may react with coal, further highlighting the difficulties in injecting CO₂ into low-permeability coal [16].

5.1 Oil and Gas fields

Oil and gas fields are regarded as prime potential sites for CO₂ storage for the following reasons:

- They have a proven seal that has retained buoyant fluids, in many cases for millions of years
- A large body of knowledge about their geological and engineering characteristics has been acquired during the exploration and production phases of development.
- In some cases there may be economic benefits to be gained from enhanced oil or gas recovery (EOR or EGR respectively) in conjunction with CO₂ storage.

5.1.1 Oil fields

Most of the UK's large offshore oil fields are in the Northern and Central North Sea Basin (Figure 3). However, there are three major fields (Clair, Foinaven and Schiehallion) in the Faroes-Shetland Basin, two (Douglas and Lennox) in the East Irish Sea Basin, and one (Beatrice) in the Inner Moray Firth Basin. There are also a number of onshore fields, most of which are very small. These are concentrated in the East Midlands and the Wessex Basin (in southern England). By far the largest of these is the Wytch Farm field, which underlies Poole Harbour, on the south coast of England.

It is considered probable that any CO₂ storage in a UK oil field would take place in conjunction with enhanced oil recovery (EOR) because the potential returns from the additional oil recovered are thought likely to exceed the extra costs involved.

However, the costs of adapting offshore platforms and other infrastructure for EOR as opposed to pure CO₂ storage are not well known at present. Moreover, the economics of EOR offshore are dependent on the oil price and potentially on the price of CO₂ in the EU ETS, both of which have shown volatility over the last few years.

Storage Capacity of the UK's Onshore Oil Fields

With one exception, the UK's onshore oil fields are too small to have any significant CO₂ storage capacity. The exception is the Wytch Farm oil field, Dorset, which is significantly larger than any of the other onshore fields, is partially offshore and is considered in the estimate for offshore fields given below.

Storage Capacity of the UK's Offshore Oil Fields

The most detailed estimate of the CO₂ storage capacity of the UK's offshore oil fields in the public domain is an estimate of the mass of CO₂ likely to be retained in the

fields as a result of stand-alone EOR [17], currently downloadable at http://www.ogmrp.com/dissemination/co2/co2_ogmrp_overview_update_eb250406.pdf

(accessed 29/4/2008). It is based on field-by-field CO₂-EOR retention estimates, made for the DTI (now DBERR) between 1989 and 1991. The study included an initial screening in which fields were excluded from consideration if they had already ceased production, their predicted close of production dates were too close, the stock tank oil initially in place was less than 100 million barrels, they were field types where the outcome of EOR was uncertain, viz. viscous oil fields, thin oil rims, fractured reservoirs, gas/condensate fields, or they were not considered suitable candidates for EOR for other technical reasons. The results of this study were updated in 2006, and include graphs showing the window of opportunity for CO₂ storage and potential annual CO₂ storage rates resulting from EOR.

The total CO₂ storage capacity of the oil fields is estimated to be approximately 1200 million tonnes. There may be upside potential because this figure does not include any CO₂ storage that might take place after stand-alone EOR had ceased. On the other hand it may be optimistic because it assumes that EOR will be deployed at all the technically suitable large oil fields.

Currently, the data indicate that the window of opportunity for EOR stretches out to 2030, and 2011 is a key year for implementing CO₂ storage associated with EOR in the UK's oil fields as the available storage capacity drops markedly thereafter.

However, latest start dates for EOR in each field are influenced by close of production dates which themselves are influenced by economic factors including the price of oil, which has risen greatly during the last few years.

The level of technical detail that has gone into these estimates is high, and potential annual CO₂ storage rates have been calculated, although field-by-field estimates are not in the public domain. Therefore they can probably be considered “matched capacity” in terms of [13].

It is possible that economic EOR could either continue for longer and thus store more CO₂, or be optimised to store more CO₂, if a value could be assigned to CO₂ storage via a mechanism such as the EU Emissions Trading Scheme (EU ETS). For example, it has been estimated that the maximum CO₂ storage capacity of the oil fields in the UK sector is 1.8 Gt CO₂ when standard EOR practices are applied [18]. Standard EOR practices imply the minimization of CO₂ usage and the maximization of CO₂ recovery after injection underground, to reduce the costs of the process by reducing CO₂ purchases. If the storage of CO₂ had a commercial value, for example through emissions trading, CO₂-EOR operations could be designed to maximize the retention of CO₂ underground. In this case, it is suggested the UK storage capacity could increase to approximately 3.5 Gt [18].

Thus the potential CO₂ storage capacity of the UK’s oil fields depends on assumptions about how they will be exploited. The potential ranges from approximately 1200 Gt CO₂ to approximately 3.5 Gt CO₂. It is considered that the most rigorous estimates are those made for the DTI [17] and therefore the realistic potential is much closer to the former figure than the latter.

How much oil could be recovered by EOR in the UK oil fields?

It has been estimated that approximately 2 billion additional barrels of oil could be recovered by economic EOR on the UKCS [17]. Disregarding economics, approximately 2.7 billion barrels (range between 1.8 and 3.7 billion barrels depending

on the achievable oil recovery from each oil field), or 58% of the UK proven reserves in 2003, could be recovered from the UK sector of the North Sea [18].

CO₂-enhanced oil recovery in North American onshore oilfields regularly recovers 4-12% of the oil initially in place [19]. A study of a section of the Forties oil field (UK North Sea) indicated that WAG CO₂-EOR could recover up to an additional 9.8% of the oil initially in place [20].

5.1.2 Storage Capacity of the UK's Gas Fields

Onshore Gas Fields

The UK's onshore gas fields are all too small to have significant CO₂ storage capacity. They are also in high demand as natural gas storage sites. The largest onshore field is Saltfleetby, in Lincolnshire. This has ultimately recoverable reserves of 2.067×10^9 standard m³ natural gas and is estimated to have a CO₂ storage capacity of 5 Mt CO₂ or less. Moreover, some of the infrastructure that has been installed has been laid out in anticipation of future use as a natural gas storage site [21], implying that it will not be available for CO₂ storage in the foreseeable future.

Offshore Gas Fields

The term gas field is applied here to hydrocarbon fields sometimes known as 'dry' gas fields because they contain methane plus only low amounts of the higher hydrocarbons that may be gaseous at reservoir conditions but which condense at surface temperatures and pressures. In other words they do not generate liquid condensate at surface conditions. Fields that contain relatively high amounts of higher hydrocarbons that are gaseous at reservoir conditions but which condense at surface temperatures and pressures are described as wet gas fields. Gas condensate fields are fields in which the hydrocarbons are gaseous at initial reservoir conditions, but they

contain very significant proportion of higher hydrocarbons which can condense to liquids in the reservoir if the pressure drops below its dew-point. They also produce condensates at the surface.

The UK's offshore gas fields occur mainly in two areas: the Southern North Sea Basin and the East Irish Sea Basin (Figure 3). However, there is also one major depleted gas field (Frigg) in the Northern and Central North Sea Basin. The gas condensate fields are all in the Central and Northern North Sea Basin.

The Southern North Sea fields

The majority of the gas field reservoirs in the UK sector of the Southern North Sea are in the Leman Sandstone Formation, a sandstone reservoir rock of Permian age.

However, there are several fields with Carboniferous sandstone reservoirs and a few with reservoirs in the Bunter Sandstone Formation, which is of Triassic age. There are also some small discoveries with reservoirs in Upper Permian (Zechstein) carbonates.

Some of the Rotliegend gas reservoirs are highly compartmentalised, i.e. they are divided into compartments by faults that act as permeability barriers. This is significant because each compartment in which CO₂ is stored is likely to require a separate CO₂ injection well, adding to the cost of storage. By contrast, the Triassic reservoirs do not appear to be significantly compartmentalised.

The majority of the fields with Rotliegend (Leman Sandstone) reservoirs are depletion-drive fields, i.e. there is little water encroachment into the field from surrounding parts of the reservoir rock during production. This means that there will be significant volumes of pore space in the field filled with low-pressure natural gas at the time that production ceases. This is advantageous for CO₂ injection because the various reservoir compartments can be filled with CO₂ and the initial reservoir

pressure may never have to be exceeded, significantly lowering the risk of leakage. At least some of the Carboniferous and Triassic fields have significant water drive, i.e. water does encroach into the field from surrounding parts of the reservoir rock during production. One exception is the Triassic Hewett Sandstone reservoir in the Hewett field.

The East Irish Sea fields

The East Irish Sea Basin fields all have reservoirs in the Ormskirk Sandstone Formation, which is of Triassic age and forms the uppermost part of the Sherwood Sandstone Group. They are sealed by the overlying Mercia Mudstone Group, which contains thick units of halite (rock salt). The two largest fields, South Morecambe and North Morecambe are principally depletion drive fields.

Northern and Central North Sea Fields

The now depleted Frigg field was the largest of the dry gas fields in the Northern and Central North Sea Basin, and the only significantly sized field outside the Southern North Sea and East Irish Sea Basins. It straddles the UK/Norway median line (Figure 3). It had strong water drive.

Storage capacity estimates

Based on the assumption that all fields would be filled with CO₂ to their initial (pre-production) pressure, total storage capacity in the gas fields in the UK sector of the Southern North Sea is estimated to be approximately 3.9 Gt CO₂ [22] and total storage capacity in the East Irish Sea Basin is estimated at approximately 1 Gt CO₂ [23].

It has been estimated that up to 4.6% EGR might be achievable in typical Leman Sandstone Southern North Sea gas fields, with low reservoir pressures and low CO₂

injection rates. However, this would require investment in an additional injection well in each compartment of the field [24].

5.1.3 Gas Condensate Fields

Gas condensate fields contain principally methane, butane, pentanes and higher hydrocarbons. This hydrocarbon mixture is in the gaseous phase in the reservoir, but the pentanes and higher hydrocarbons condense to liquids at surface temperature and pressure. In the UK, gas condensate fields are only found in the Northern and Central North Sea Basin (Figure 3). Less field-by-field public domain information on their drive mechanism is available, but a crude estimate of their CO₂ storage capacity, using the same assumptions that were made for the dry gas fields, is 1.2 Gt CO₂ [22].

5.1.4 Saline water-bearing reservoir rocks (saline aquifers)

The CO₂ storage capacity of saline water-bearing reservoir rocks is extremely difficult to estimate, particularly on a regional basis. The storage capacity of a small volume of an aquifer such as an individual structural closure can be estimated by numerical simulation of CO₂ injection. At least three of the five potential CO₂ trapping mechanisms should be taken into account (geochemical trapping can often be neglected on the grounds that it is such a slow process that it is unlikely to affect storage capacity over injection timescales and adsorption is not likely to be significant unless the reservoir contains significant volumes of coal). Detailed knowledge of the reservoir properties, the structure of the reservoir and the structure and hydraulic properties of surrounding strata are required for accurate simulation.

The limits to the amounts of CO₂ that could be stored in any part of, or an entire, aquifer are determined by the thresholds at which adverse effects will occur. The most important of these is commonly leakage from the storage reservoir but the potential to

adversely affect other legitimate uses of the subsurface, ground surface or marine environment may also need to be considered.

It is commonly uncertain whether, or under what conditions, structural or stratigraphic traps in aquifers are gas-tight, i.e. will not leak when filled with CO₂. The principal means by which CO₂ is likely to leak through the natural sealing system is through capillary entry into the sealing formation or through fractures in the sealing formation, which may be on various scales. The potential for capillary leakage through the seal can be estimated from laboratory capillary entry pressure measurements.

Geomechanical tests or modelling can be used to estimate the limiting reservoir pressure above which any faults or fractures might slip or dilate, or fractures might be induced in the reservoir rock or sealing formations: the maximum safe local or regional pore fluid pressure rise induced by CO₂ injection can potentially be a significant constraint on storage capacity. Inducing regional pore fluid pressure rise in a reservoir formation could be construed as interfering with other CO₂ storage operations, or even oil or gas production. The integrity of any wells on the migration path of the injected CO₂ also needs to be considered, as does the impact of acidified pore water (caused by CO₂ dissolution into the native pore water found in the aquifer) on the entire system - including any wells.

There are also cultural constraints that restrict the CO₂ storage potential in aquifers, particularly in onshore and nearshore regions. Those parts of aquifers that contain potable water should be protected from potential contamination by injected CO₂ or displaced saline water or entrained substances such as oil or heavy metals mobilised by CO₂ injection.

CO₂ storage potential in UK onshore saline water-bearing reservoir rocks

Amongst the major deep aquifers of onshore Britain, there is, in general, a correspondence between sandstones that have sufficient porosity and permeability to form a low-enthalpy geothermal resource [25] and those that have the potential for CO₂ storage. These sandstones also tend to be used for water supply in areas where they crop out at the surface or are buried to only shallow depths and consequently are unlikely to be considered for CO₂ storage. Only the Lower Greensand, Portland Sand, Sherwood Sandstone and various Permian sandstones are considered sufficiently porous and permeable to have large-scale CO₂ storage potential [26].

CO₂ storage potential in UK offshore saline water-bearing reservoir rocks

Attempts have been made to estimate the theoretical CO₂ storage capacity of various areas or formations within the UKCS [22, 23, 27]. These indicate several Gt CO₂ storage capacity in the Southern North Sea Basin and some more limited potential (up to 0.63 Gt) in the East Irish Sea Basin. However, none of these studies take into account all the major factors that should be considered in such an analysis and so the saline aquifer CO₂ storage capacity even of these regions needs to be revisited. In particular, the local and regional pore fluid pressure rise in a potential saline aquifer storage formation needs to be considered as well as the pore volume and the CO₂ saturation that is likely to be achieved in the closed structures. This requires numerical simulation of concurrent multiple CO₂ injection projects in the aquifer as a whole. Such simulation needs to take into account the hydraulic properties of the surrounding strata as well as the potential storage reservoir.

6. Conclusions

There is very significant CO₂ storage capacity in the UK's oil and gas fields.

Accessing and utilising this is a significant issue under present economic conditions.

There is undoubtedly great storage potential in the saline water-bearing reservoir

rocks of the basins around the UK as well, but calculating the magnitude of this potential resource is beset with problems. The real challenge for studies of aquifer CO₂ storage capacity in the UK is perhaps not to estimate the total theoretical CO₂ storage capacity, as this is not a particularly meaningful number. Rather it is to thoroughly investigate selected reservoirs perceived to have good storage potential, to a standard where there is scientific consensus that the resulting storage capacity estimates are realistic. This will allow it to be considered as closer to the status of a reserve rather than a resource and will help define the scope for CCS in the UK.

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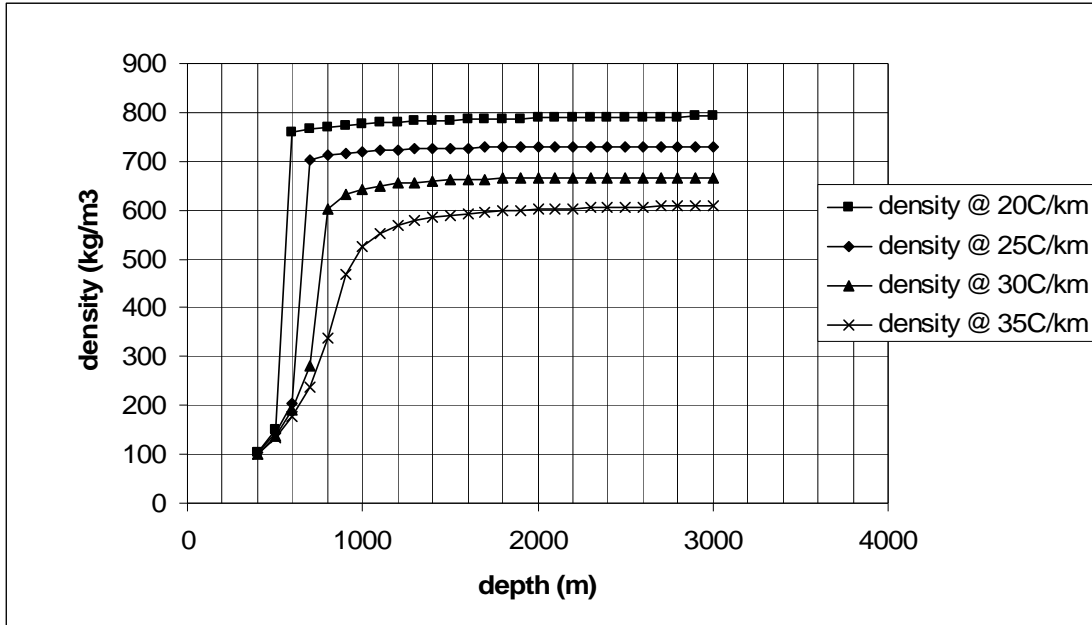


Figure 1. Density of CO₂ at a range of geothermal gradients typically found in sedimentary basins, assuming a surface temperature of 10°C and a hydrostatic pressure gradient.

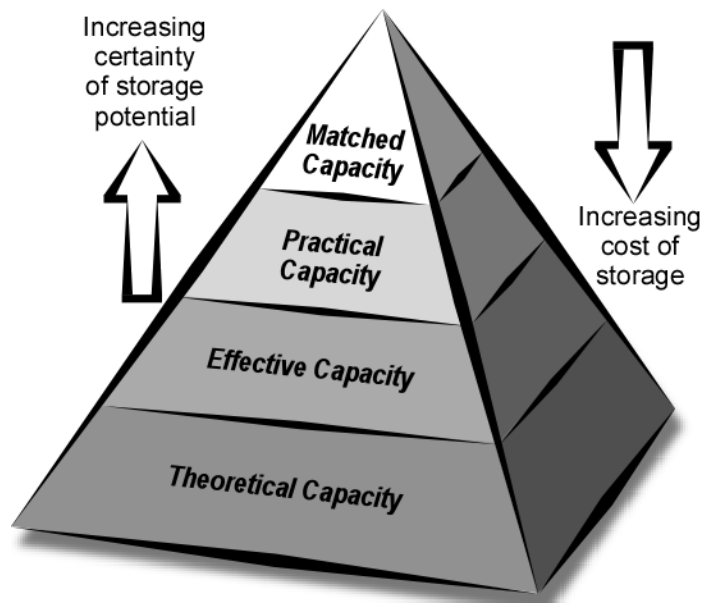


Figure 2. Techno-Economic Resource-Reserve pyramid for CO₂ storage capacity in geological media within a jurisdiction or geographic region. The pyramid shows the relationship between Theoretical, Effective, Practical and Matched capacities (from Bachu et al. 2007).

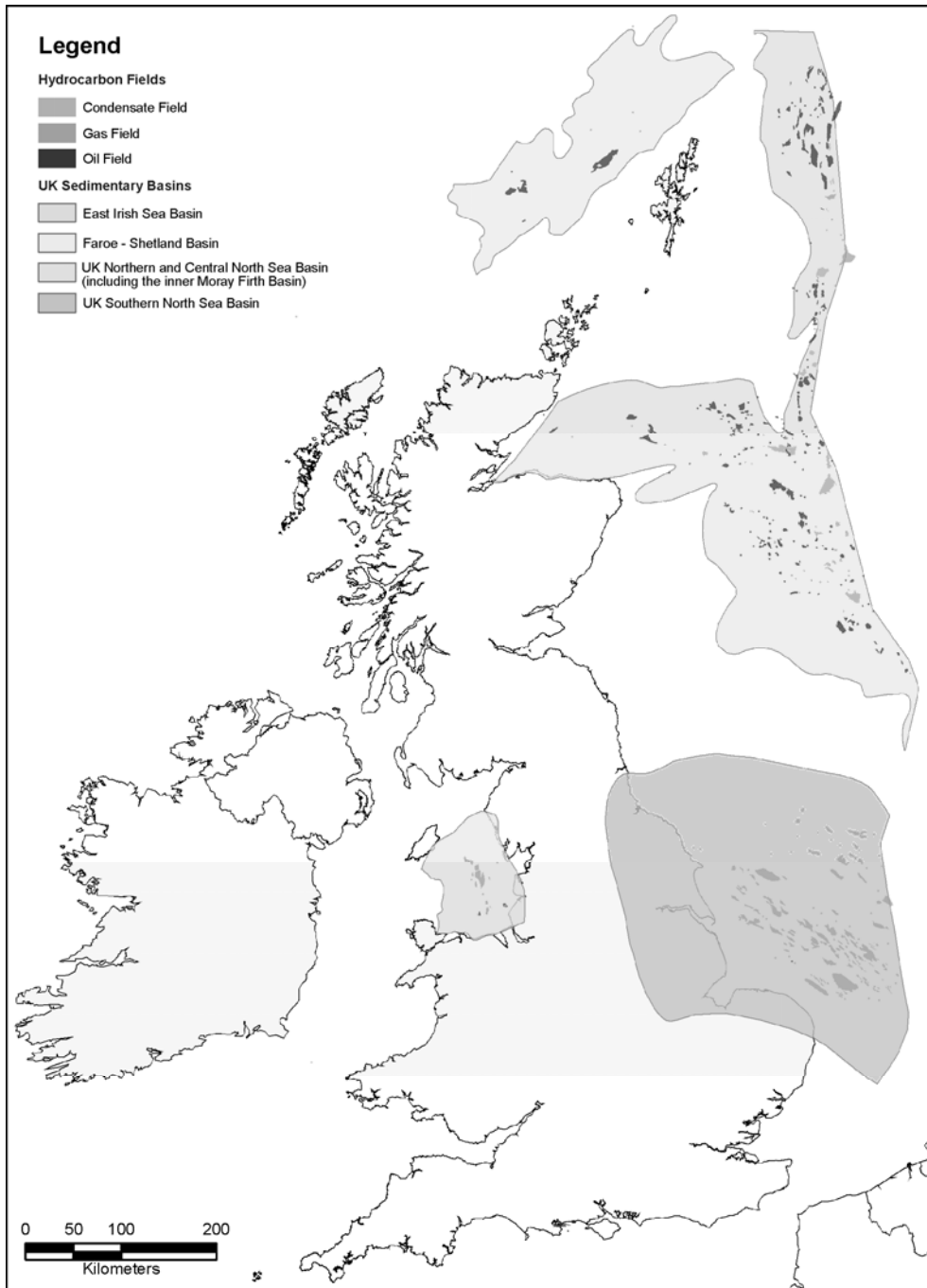


Figure 3. Map showing the location of offshore hydrocarbon fields and the major oil and gas-bearing sedimentary basins in the UK Continental Shelf.