On the impact of maximum allowable cost on CO_2 storage capacity in saline formations

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ABSTRACT

Injecting CO_2 into deep saline formations represents an important component of many greenhouse gas reduction strategies for the future. A number of authors have posed concern over the thousands of injection wells likely to be needed. However, a more important criterion than the number of wells is whether the total cost of storing the CO_2 is market bearable. Previous studies have sought to determine the number of injection wells required to achieve a specified storage target. Here an alternative methodology is presented whereby we specify a maximum allowable cost (MAC) per tonne of CO_2 stored, a priori, and determine the corresponding potential operational storage capacity. The methodology takes advantage of an analytical solution for pressure build-up during CO_2 injection into a cylindrical saline formation, accounting for two-phase flow, brine evaporation and salt precipitation around the injection well. The methodology is applied to 375 saline formations from the UK Continental Shelf. Parameter uncertainty is propagated using Monte Carlo simulation with 10,000 realisations for each formation. The results show that MAC affects both the magnitude and spatial distribution of potential operational storage capacity on a national scale. Different storage prospects can appear more or less attractive depending on the MAC scenario considered. It is shown that, under high well injection rate scenarios with relatively low cost, there is adequate operational storage capacity for the equivalent of 40 years of UK CO_2 emissions.

INTRODUCTION

Carbon capture and storage (CCS) is considered a necessary and significant contributor in plans for reducing anthropogenic global CO_2 emissions in the future [1-3]. Cost is currently one of the main barriers to the development of CCS infrastructure projects in advance of market demand, and the largest part of this is associated with capture technology [4]. However, uncertainty concerning CO_2 storage capacity and its development is also a major technical and commercial obstacle [4]. This is especially the case for saline formations [5], which represent the largest proportion of available storage sites worldwide [1]. The term saline formation is used here to describe a saline aquifer containing water that is too salty to be considered for potable use.

The process of storing CO_2 in saline formations involves drilling wells and injecting CO_2 into the pore space of a saline formation. The long-term, theoretical potential storage capacity of such sites is dependent on structural, residual, dissolution and mineralisation trapping mechanisms. This long-term potential storage capacity is hereafter referred to as the static capacity. The term operational storage capacity is used here for that capacity which is achievable under typical industry operating conditions. This capacity is constrained by a number of factors including static capacity, cost and the maximum allowable pressure build-up in the storage formation [6].

Pressure build-up is an important constraint because, as CO_2 is injected into the saline formation, the pore-space accommodates the new fluid locally by compressing the rock matrix and the previously residing formation waters [7]. This in turn leads to an increase in pressure within the saline formation, which will be especially high around the injection well. It is undesirable to have excessive pressure build-up because this may lead to fracturing of the cap-rock, re-activation of faults and/or other mechanisms that can result in migration of the CO_2 outside the storage formation [8, 9].

Local pressure reduction can be achieved by distributing the injected CO_2 across multiple injection wells. But in a controversial numerical simulation study, Ehlig-Economides and Economides [10] concluded that hundreds of wells would be required to store just 30 years of emissions from one coal-power plant. One limitation of the study was that the mathematical model assumed the saline formation is completely confined (i.e., surrounded on all sides by impermeable boundaries). Cavanagh et al. [11] argue that significantly more CO_2 can be stored in saline formations that have pressure connection to much larger external geological systems. However, when many wells are applied in close proximity, the pressure interference between wells causes individual injection wells

to act as if contained within completely confined saline formation units [12, 13]. Therefore, even open saline formation systems, where not all the boundaries are impermeable, may behave as completely confined systems if large numbers of wells are required due to poor injectivity (where relatively small injection rates lead to relatively high pressure build-up).

More importantly, Cavanagh et al. [11] argue that the dimensions of the saline formation considered by Ehlig-Economides and Economides [10] (873 km^2 area and 30.5 m thickness) were significantly smaller than those considered by many other studies. For example, the saline formations described by Jin et al. [14] were of the order of 2000 km^2 area and 300 m thickness and those listed in table 6 of SCCS [15] have areas ranging from 1712 km^2 to 17147 km^2. Nevertheless, Ehlig-Economides and Economides [10] raise the interesting point that drilling thousands of injection wells to store small amounts of CO_2 is an uneconomic prospect. This is particularly so in an offshore environment such as the UK Continental Shelf.

However, for commercial deployment of CCS the major concern will not be the number of wells required but instead the total cost of storing the CO_2. In a recent study, Carneiro et al. [16], using similar methods to Ehlig-Economides and Economides [10], estimated the cost of storing CO_2 in 43 different saline formation storage hubs across Spain, Portugal and Morocco. They found that the storage cost per tonne of CO_2 (excluding the cost of capture, compression and transmission) ranged from 1.4 to 116.3 €2007. Their approach was to take a saline formation unit, apply a pre-assigned number of injection wells (typically 4) and then assess the maximum injection rate per well that could be sustained for 30 years.

Another way to approach the topic of numbers of injection wells for commercial development is to determine a maximum allowable cost per tonne of CO_2 stored, impose this on a given saline formation and then determine the associated operational storage capacity. The term, maximum allowable cost (MAC), is hereafter used to refer to an imposed maximum cost per tonne of CO_2 stored. Operational storage capacity is likely to reduce with reducing MAC. In this article we demonstrate how MAC can be expected to affect the operational CO_2 storage capacity that can be utilised at a regional and national scale by analysing a database of 375 saline formations from offshore UK. The findings will be of significant benefit for developing a national portfolio of UK site appraisal options. The presented methodology should also be widely applicable to national appraisal studies elsewhere in the world. Minimum input data required for candidate storage saline formations includes: depth, geothermal gradient, pore-pressure, permeability, porosity, areal extent and formation thickness.

The outline of this article is as follows. First, a set of suitable cost scenarios are developed and proposed. A methodology is described to estimate operational storage capacity as a function of MAC. Following on from this, some case studies are presented from the UK CO_2 Stored® database [17]. An analysis is then performed to explore how MAC affects operational storage capacity in terms of both magnitude and spatial distribution.

MATERIALS AND METHODS

Development of cost scenarios

The total cost of storing a given quantity of CO_2 is strongly dependent on the required number of injection wells. The number of injection wells is in turn controlled by the sustained injection rate applicable to each well, which can be different to the initial injection rate achieved on well completion. Hosa et al. [18] reviewed injection rates at 15 operating or planned CO_2 storage projects around the world. The largest injection rate per well reported was 3.65 Mt/year. Ten of the reported rates were less than 1 Mt/year. Five of the reported rates were less than 0.1 Mt/year.

Mathias et al. [19] showed that the injection rate statistics from Hosa et al. [18] are very similar to bulk fluid production rates (i.e., combined volumetric rates of oil, water and gas at reservoir conditions) from 104 offshore UK oil and gas fields. By averaging production rates over a ten year period, Mathias et al. [19] showed that 50% of the production wells studied produced bulk fluid at a rate of less than 3.5 million barrels per year. Assuming a CO_2 density of 650 kg/m^3, this volumetric rate converts to around 0.35 Mt/year.

Collectively, the studies of Hosa et al. [18] and Mathias et al, [19] suggest that many CO_2 injection wells are likely to achieve sustained rates of up to 0.1 Mt/year, whilst very few injection wells are likely to achieve injection rates greater than 1 Mt/year. Based on these studies, we will consider four injection rate scenarios: 0.1 Mt/year, 0.5 Mt/year, 1.0 Mt/year and 2.5 Mt/year. The latter rate represents a very optimistic scenario for storage sites located on the UK Continental Shelf.

These injection rates can be thought of as representing different cost scenarios, the smallest rate representing the most expensive scenario. An indication of the total investment cost of these scenarios, for a given quantity of CO_2 to be stored, can be obtained by utilising the equation (modified from [20]):

$$I = \lfloor N(LC_d + C_w + C_{sf}) + C_{sd} + C_m \rfloor (1 + f) \quad (1)$$

where I (€) is investment cost, N (-) is the number of injection wells, L (m) is the injection well length, C_d (€/m) is the drilling cost per metre length of well, C_w (€/well) is a fixed cost per well, C_{sf} (€/well) is the cost for the surface facilities on the injection sites, C_{sd} (€) is the cost of site development, C_m (€) is the cost of emplacement of monitoring equipment and f (-) is a factor to be applied to the total cost to account for additional operating, maintenance and monitoring (OMM) costs.

Building on the work of van den Broek et al. [20], Carneiro et al. [16] provide values for the above cost parameters in 2007€ for deep offshore saline formations as follows: C_d = €26 k per m, C_w = €8,200 k per well, C_{sf} = €6,120 k per well, C_{sd} = €24,097 k, C_m = €1,530 k. They further suggest an OMM factor of $f = 0.05$.

Applying Eq. (1) with the parameter values listed above and assuming a uniform well length of L = 2000 m leads to the following equation for estimating the associated storage cost per tonne of CO_2 stored, C_{st} (€/tonne):

$$C_{st} = 69.64(1 + 0.386/N)/(M_0 t_0) \quad (2)$$

where M_0 (Mt/year) is the injection rate applied to each well and t_0 (years) is the duration of injection. From Eq. (2) it is clear that for situations with large numbers of wells, the cost of storage is approximately inversely proportional to the injection rate. Therefore it can be concluded that the costs per tonne of CO_2 stored shown in Table 1 are largely independent of the saline formation size considered.

Table 1 shows some corresponding costs associated with the four injection rate scenarios for a saline formation with 4000 Mt potential static capacity (typical of the list studied by SCCS [15]) with each injection well assumed to be 2000 m long and operating at a constant rate for 20 years.

Note that even with an overly optimistic sustained injection rate of 2.5 Mt/year per well, this would require 80 wells and would cost €5.6 billion. If we consider the pessimistic (but more realistic) scenario of 0.1 Mt/year, 2000 wells would be required and the cost would be €139.3 billion. Hence the cost per tonne of CO_2 ranges from €1.39 to €34.82. For comparison, Herzog [21] calculated that

the cost of capture and compression of CO_2 from a supercritical pulverised coal power plant to be around €70.47 / tonne of CO_2 (based on a 2007 Euro to US dollar exchange rate of 1.35) (note that Herzog's [21] price is stated in USD2007). It can therefore be understood that the most expensive storage option would still be under half the anticipated cost associated with capture and compression.

Table 1: Storage costs for 100% utilisation of a 4000 Mt saline formation based on Eq. (1) and assuming each injection well operates for 20 years. These costs are based on 2007 prices previously published by Carneiro et al. [16].

Injection rate, M_0 (Mt/year)	0.1	0.5	1	2.5
Number of wells, N	2000	400	200	80
Total storage cost, I (€Billion)	139.3	27.9	14.0	5.6
Cost per tonne of CO_2, C_{st} (€)	34.82	6.96	3.48	1.39

Whilst the total cost of storing a given quantity of CO_2 is strongly dependent on the number of injection wells used, Eq. (2) shows that the cost per tonne of CO_2 stored becomes independent of the number of injection wells when a large number of wells are required. This can be explained as follows: The per-well cost of storage dominates the total cost (given by Eq. (1)) such that the total cost is nearly proportional to the number of wells used. When all the injection wells are operating at the same rate and for the same duration, the mass of CO_2 stored is also proportional to the number of wells. Therefore, the number of wells effectively cancels out when considering the cost per tonne of CO_2 stored. The above findings assume that the injection rate and injection duration are independent of the number of wells. However, a methodology that more realistically incorporates this dependency is explained in the sub-section below.

Determining storage capacity for a given maximum allowable cost (MAC)

The operational storage capacity associated with a given saline formation for a MAC (such as the C_{st} values presented in Table 1) can be determined by assessing how many injection wells can operate within the saline formation at the associated injection rate for the specified time (i.e., 20 years in Table 1). The approach taken for determining operational storage capacity for a given saline formation in this study is described as follows:

Firstly, the static capacity, m_{stat} [M], of the saline formation is obtained by determining the pore-volume of the saline formation, multiplying by the density of CO_2 at reservoir conditions and then

multiplying by an efficiency factor, as described by Gammer et al. [22]. The static capacity represents an upper limit on operational storage capacity, as described in the introduction and by Szulczewski et al. [6]. The next stage is to determine the maximum operational storage capacity, m_{max} [M], that can be achieved for each of the four MAC scenarios associated with the injection rates, M_0 [MT^{-1}], in Table 1.

A sequence of 37 different saline formation utilisation rates, U_0 [MT^{-1}], is considered ranging from 0.1 to 1000 Mt/year. The term utilisation rate is used here to describe the rate at which CO_2 is injected into a saline formation unit as a whole. For a given utilisation rate, U_0, and injection rate, M_0, the number of wells, N, being considered can be obtained from $N = U_0 / M_0$. For each utilisation rate and injection rate, the maximum sustainable injection duration, t_0 [T], is determined as described in the next sub-section. Scenarios where $t_0 < 20$ years are excluded based on the assumption that operators would require their injection wells to be sustainable for at least 20 years. Values of t_0 are capped at 40 years, representing an operational design life of the saline formation. The quantity of CO_2 stored, m_0 [M], for each (U_0, M_0) scenario is found from $m_0 = U_0 \times t_0$. Following Szulczewski et al. [6], values of m_0 are capped at the static capacity, m_{stat}. The operational storage capacity, m_{max}, is taken to be the maximum value of m_0 for each injection rate, M_0.

Because all selected injection wells are in operation for at least 20 years, the C_{st} values in Table 1 can be thought of as representing the MAC associated with the corresponding set of injection rates, M_0 (also shown in Table 1). Hence it can be understood that specifying an injection rate alongside a minimum injection duration a priori is analogous to specifying a MAC calculated from Eq. (2) a priori.

Determining sustainable injection duration

Injection well pressures increase as CO_2 is injected into the saline formation. The sustainable injection duration, t_0, is the time at which the well pressure reaches a specified upper limit, P_{max} [ML^{-1}T^{-2}]. For the current study, P_{max} was taken to be the minimum of 90% of the fracture pressure, 90% of the lithostatic pressure and 100% of the estimated downhole pressure that can be sustained by a surface pressure of 25 MPa (i.e., surface pressure + gravity head – frictional loss within the standing pipe). The latter constraint is based on the assumption that all compression is located on-shore.

Using a study of stress gradients in the Central Graben and the Scotian Shelf by Engelder and Fischer [23], the fracture pressure, P_{frac} (Pa), is estimated from the empirical equation:

$$P_{frac} = 0.71 P_p + 8500z \qquad (3)$$

where P_p (Pa) and z (m) are the pore-pressure and depth below seabed for a given saline formation, respectively.

Following, Mijic et al. [12], the presence and interference of multiple wells is treated by splitting the saline formation into equal areas for each well. Each well is then assumed to be situated within the centre of a cylindrical completely confined saline formation surrounded with impermeable boundaries.

The pressure build-up in each well as a function of time is estimated using the analytical solution of Mathias et al. [24]. This model assumes that CO_2 is injected into the centre of a cylindrical homogenous and completely confined saline formation. Flow of fluid is assumed to be a one-dimensional radially symmetric process. Other limiting assumptions include that capillary pressure is negligible and fluid properties are constant. The model is able to account for non-linear relative permeability, the development of a dry-out-zone and salt precipitation around the well due to evaporation of water and reduction of volumetric flow rate due to CO_2 dissolution into the brine. Comparisons with fully dynamic simulations using TOUGH2 have shown this analytical solution to be sufficiently accurate for this purpose Mathias et al. [24, 25].

Following Mathias et al. [25], all the relevant fluid properties for CO_2 and brine are calculated using equations of state provided by Batzle and Wang [26], Fenghour et al. [27] and Spycher and Pruess [28]. Rock compressibility is calculated as a function of porosity using the correlation for sandstones of Jalalh [29]. Permeability reduction due to salt precipitation around the injection well is simulated using the power law expression provided by Mathias et al. [25], which is based on an experimental data set previously presented by Bacci et al. [30].

The above procedure is suitable for completely confined saline formations, which are impermeable on all sides. For open saline formation systems, the approach is modified as follows. For scenarios involving less than 8 injection wells, the area of the saline formation is re-scaled by multiplying by the efficiency factor (as defined in the Gammer et al. [22] study) and then dividing by the equivalent efficiency factor for a completely confined saline formation system. When more than 8

injection wells are applied, the area reverts back to its original value, under the assumption that the central well behaves as if in a completely confined saline formation due to the interference from neighbouring wells. An important assumption here is that the original open saline formation is vertically confined by impermeable overlying and underlying formations.

The above procedure was devised by an expert panel associated with the work of Gammer et al. [22]. The basic idea assumes that once nine injection wells are present, there is one well in the middle of a square nine-spot arrangement, which behaves as if in a completely confined saline formation due to interference from the surrounding eight injection wells. Although such a procedure appears quite arbitrary, it is useful in terms of recognising that as more injection wells are applied, some injection wells in an open saline formation are unable to benefit from being able to propagate associated local pressure build-up to open lateral boundaries.

In general, it is understood that operational storage capacity, $m_{\max}$, should increase with increasing numbers of wells. However, a disadvantage of the above approach is that in some cases, increasing the number of wells can lead to reduced $m_{\max}$ as the saline formation is discontinuously perceived to transform from an open to a completely confined saline formation system. Therefore a correction is applied whereby $m_{\max}$ is assumed to remain constant with increasing number of wells unless it increases with increasing number of wells.

Analysis of the CO_2 Stored® database

The UK Storage Appraisal Project (UKSAP), commissioned by the UK's Energy Technologies Institute (ETI), compiled a database of relevant technical and commercial parameters for over 500 potential offshore CO_2 storage sites on the UK Continental Shelf, including 375 offshore saline formations [22]. Uncertainty was dealt with by experts reaching consensus on the minimum, maximum likelihood and maximum value for each parameter assuming triangular distributions. For each saline formation unit, distributions were specified for, among other things: water depth, area, formation thickness, areal net sand ratio, net to gross ratio (NTG), porosity, shallowest depth, depth to centroid, salinity, permeability, lithostatic gradient, geothermal gradient and overpressure. The data is available within the CO_2 Stored® online database [17]. These parameters are sufficient to fully parameterise the model above for each saline formation unit. Note UKSAP also assumed that each saline formation can be treated as a single homogenous unit.

The model framework, described in the previous sub-sections, was applied to each of the 375 offshore saline formations so as to determine estimates of operational storage capacity for each of the four allowable cost scenarios. Prescribed parameter uncertainty from CO_2 Stored® was propagated through to storage capacity estimation by running the model within a Monte Carlo simulation whereby each of the parameters was randomly sampled from the specified triangular distributions. So as to ensure statistical convergence, 10,000 realisations were run for each saline formation. The entire modelling framework was conducted within the MATLAB programming environment. On a 12 core desktop computer, 10,000 simulations of a single saline formation take about 5 minutes to complete.

Unfortunately, the CO_2 Stored® database does not contain explicit information concerning relative permeability data for CO_2 and brine mixtures for UK saline formation rocks. Recently Mathias et al. [25] compiled results from 25 different sandstone and carbonate reservoir rocks from around the world. Following the recommendations of Mathias et al. [25], relative permeability uncertainty is treated by randomly selecting one of these 25 results for each of the 10,000 saline formation realisations.

RESULTS AND DISCUSSION

So as to gain further insight into how this methodology works, Fig. 1 shows results from six of the saline formations previously studied for static capacity by SCCS [15]. All six units lie in close proximity to North West Scotland. A location map is available in Figure 13 of SCCS [15]. Specifically, Figs. 1 a and b illustrate how operational storage capacity reduces with increasing injection rate. For reference, corresponding values for MAC, based on Eq. (2), are shown on the upper x-axes of the plots. Recall that operational storage capacities have been determined using Monte Carlo simulation. P10, P50 and P90 relate to results with probability of non-exceedances of 10, 50 and 90%, respectively. It can be seen that the P50 operational storage capacity reduces to zero at 1.75 Mt/year for Mey, Forties and Tay. In contrast, a high level of P50 operational storage capacity persists beyond 2.5 Mt/year for Heimdal, Frigg and Captain.

SCCS [15] previously reported upper and lower bound estimates of static capacity, for the same saline formations studied in Fig. 1, obtained by multiplying estimates of the associated pore-volumes by efficiency factors of 0.02 and 0.002, respectively. Note that the operational storage capacities reported for zero injection rates in Figs. 1 a and b are analogous to static capacity

estimates. The P50 static capacities presented in Figs. 1 a and b are all found to lie within the range of the estimates previously presented by SCCS [15].

Jin [31] earlier performed a more detailed assessment on the Captain sandstone formation using a 3D statistical geological model in conjunction with a numerical reservoir simulation model. Their simulation forecasted the possibility of storing 358 Mt of CO_2 by injecting up to 2.5 Mt/year in individual wells for up to 25 years. Our much more simple approach described in this article forecasts an operational storage capacity of 223 Mt of CO_2 in this context (see Fig. 1 b).

A measure of how rapidly a saline formation becomes undesirable with decreasing MAC can be obtained by considering the efficiency ratio, E [-], found from the 1.0 Mt/year operational storage capacity divided by the associated static capacity of the saline formation. Values of E can range from zero to one. Values of E very close to one imply that operational storage capacity of the saline formation is insensitive to MAC. Small values of E imply that the saline formation rapidly loses its operational storage capacity with decreasing MAC.

A sensitivity analysis was performed to determine which key factors characterise more efficient (i.e., high E) saline formations. The sensitivity analysis was performed by calculating the Spearman's rank-order correlation between each of the input parameter values (using their maximum likelihood estimates) and the P50 value of E for each of the saline formations studied.

Considering the top three most sensitive parameters for the completely confined saline formations: the efficiency factor, E, was found to be positively correlated with permeability and formation thickness but negatively correlated with the depth of the centroid of the formation below the seabed. Permeability is particularly important here because permeability directly controls how fast the pressure build-up around the injection wells is able to dissipate within the saline formation. Larger formation thickness is important because it reduces the flow rate per unit area of CO_2 in the formation, which also leads to smaller pressure gradients. The negative correlation with formation centroid depth is harder to explain. However, it can be understood that for high geothermal gradients, the density of CO_2 reduces with increasing depth. This in turn will lead to larger volumetric flow rate per unit area of CO_2 in the formation, which in turn leads to higher pressure gradients.

Considering the top three most sensitive parameters for the open confined saline formations: the efficiency factor, E, was found to be positively correlated with permeability, formation area and the

depth of the overlying seabed below sea level. Permeability was discussed above. Sea depth is likely to have a positive effect here because it leads to higher CO_2 densities and hence a lower volumetric flow rate per unit area of CO_2 in the formation. It is not clear why efficiency is positively correlated with area. There are many complicated parameter interactions taking place for the open saline formations due to the discontinuous way in which open saline formations are treated as completely confined saline formations when the number of injection wells exceeds 8. Nevertheless, both sensitivity analyse demonstrate the obvious importance of permeability for predicting high efficiency in the saline formations.

Figs. 1 c and d show the permeability cumulative distributions for each of the example saline formations studied in Figs. 1 a and b. Those saline formations that show non-zero P50 operational storage capacity at 2.5 Mt/year all have minimum permeabilities greater or equal to 100 mD. Also of interest are the intervals between the P10 and P90 storage capacities. Captain and Frigg exhibit very tight confidence limits. In contrast, Tay exhibits a much larger level of uncertainty.

Fig. 2a shows a plot of P10, P50 and P90 operational CO_2 storage capacity against injection rate for all UK offshore saline formations from the CO_2 Stored® database with centroid depths greater than 1000 m and less than 2500 m below sea bed, which is considered a best practice requirement in the SCCS [15] study. The results clearly indicate how UK operational storage capacity could be increased by increasing the MAC (recall that MAC is inversely proportional to injection rate in this context). Of particular interest is that the P10 storage capacity at an injection rate of 1 Mt/year (equivalent to (2007) €3.48 storage cost per tonne of CO_2) is around 20 Gt. For reference, 40 years of UK net emissions of CO_2 corresponds to around 19 Gt [32].

Fig. 2b shows a plot of P10, P50 and P90 number of suitable saline formations (i.e., saline formations with a greater than zero operational storage capacity) against injection rate. Note that, considering the P50 results, the centroid depths greater than 1000 m and less than 2500 m below sea bed constraint reduced the number of available saline aquifers from 375 to 113. Imposing MACs associated with injection rates of 0.1 Mt/year and 1.0 Mt/year reduces the number of available formations further to 89 and 53, respectively. The models predict that only 16 saline formations are able to deal with an injection rate of 2.5 Mt/year.

Fig. 3 shows maps of P50 operational CO_2 storage capacity at different injection rates. The rectangles correspond to quads commonly used by the UK Department of Energy and Climate Change (DECC) to manage oil and gas production licences. The white numbers are the sum of P50

operational storage capacities for all saline formation units situated within the respective quad. Here it can be seen how different areas look more or less attractive depending on the stipulated MAC.

Table 2 shows the top 3 saline formations in terms of P50 operational CO_2 storage capacity for each of the MAC scenarios presented in Table 1. Within the list, only the Heimdal formation and Forties member were presented in the earlier study by SCCS [15]. Note that the saline formation, Mey member (365), has a larger operational storage capacity for injection rates ≤ 1.0 Mt/year (recall Figure 1a). However, this was not included in Table 2 because its centroid depth is > 3000 m below seabed. The results in Table 2 only include saline formations with centroid depths between 1000 and 2500 m below seabed.

Both the St Bees and Heimdal formations are found to be top ranking (i.e., in the top 3) prospects for injection rates ≤ 1.0 Mt/year. The Maureen formation is top ranking only for the relatively high MAC scenarios of 0.1 and 0.5 Mt/year. In contrast, the Forties member and the Penrith and Mousa formations only become top ranking when considering the lower MAC scenarios of 1.0 and 2.5 Mt/year.

Table 2: Top 3 saline formations in terms of P50 operational CO_2 storage capacity for each of the maximum allowable costs scenarios presented in Table 1. The numbers in brackets are the associated formation identifier numbers used in the CO_2 Stored® database. Note these only include saline formations with centroid depths between 1000 and 2500 m below seabed.

Injection Rate (Mt/year)	Saline formation	Location	Operational capacity (Mt)
0.1	St Bees Formation (265)	East Irish Sea Basin	3410
	Heimdal Member (234)	Northern North Sea	2889
	Maureen Formation (250)	Northern North Sea	2874
0.5	St Bees Formation (265)	East Irish Sea Basin	3410
	Heimdal Member (234)	Northern North Sea	2889
	Maureen Formation (250)	Northern North Sea	2874
1	St Bees Formation (265)	East Irish Sea Basin	3410
	Heimdal Member (234)	Northern North Sea	2889
	Forties Member (372)	Central North Sea	2505
2.5	Heimdal Member (234)	Northern North Sea	2889
	Penrith Formation (261)	East Irish Sea Basin	1076
	Mousa Formation (240)	Northern North Sea	725

Currently the UK has three carbon capture projects which are moving forwards with two at the FEED (Front-End Engineering Design) stage [33]. There are two identified storage sites (the third

project will likely share one of the sites). One site is located in the depleted Goldeneye gas field in the Outer Moray Firth. It has a sandstone reservoir of Cretaceous age. The other site is located in the Southern North Sea, away from the gas province and has a saline aquifer storage site composed of Triassic age sandstone. Neither of these projects features in Table 2. However, both of these project locations were chosen for alternative economic reasons associated with already available infrastructure and proximity to specific CO_2 sources.

In summary, storing national scale quantities of CO_2 in offshore saline formations may require large numbers of wells. However, the cost of storage in this context is likely to represent a small fraction of the cost associated with capture, compression and transmission. Previous analysis has led to misleading results concerning the feasibility of CCS infrastructure deployment because technical dynamic storage capacities have been estimated for given saline formations and the associated cost subsequently derived. This article provides an alternative methodology for instead specifying a maximum allowable cost (MAC) per tonne of CO_2 stored, a priori, and deriving the associated operationally available storage capacity. Note that by consideration of economic costs published in the literature, it can be shown that, for situations with large numbers of wells, the costs per tonne of CO_2 stored is inversely proportional to the injection rate applied (recall Eq. (2)). Our results show that MAC can significantly affect both the magnitude and spatial distribution of operational storage capacity. Different storage prospects can appear more or less attractive depending on the MAC scenario considered. Furthermore, our approach demonstrates availability of affordable storage at a scale comparable to national UK emissions – reinforcing the validity of CCS as a decarbonisation technology for the UK, and by extension other regions with saline formation storage potential.

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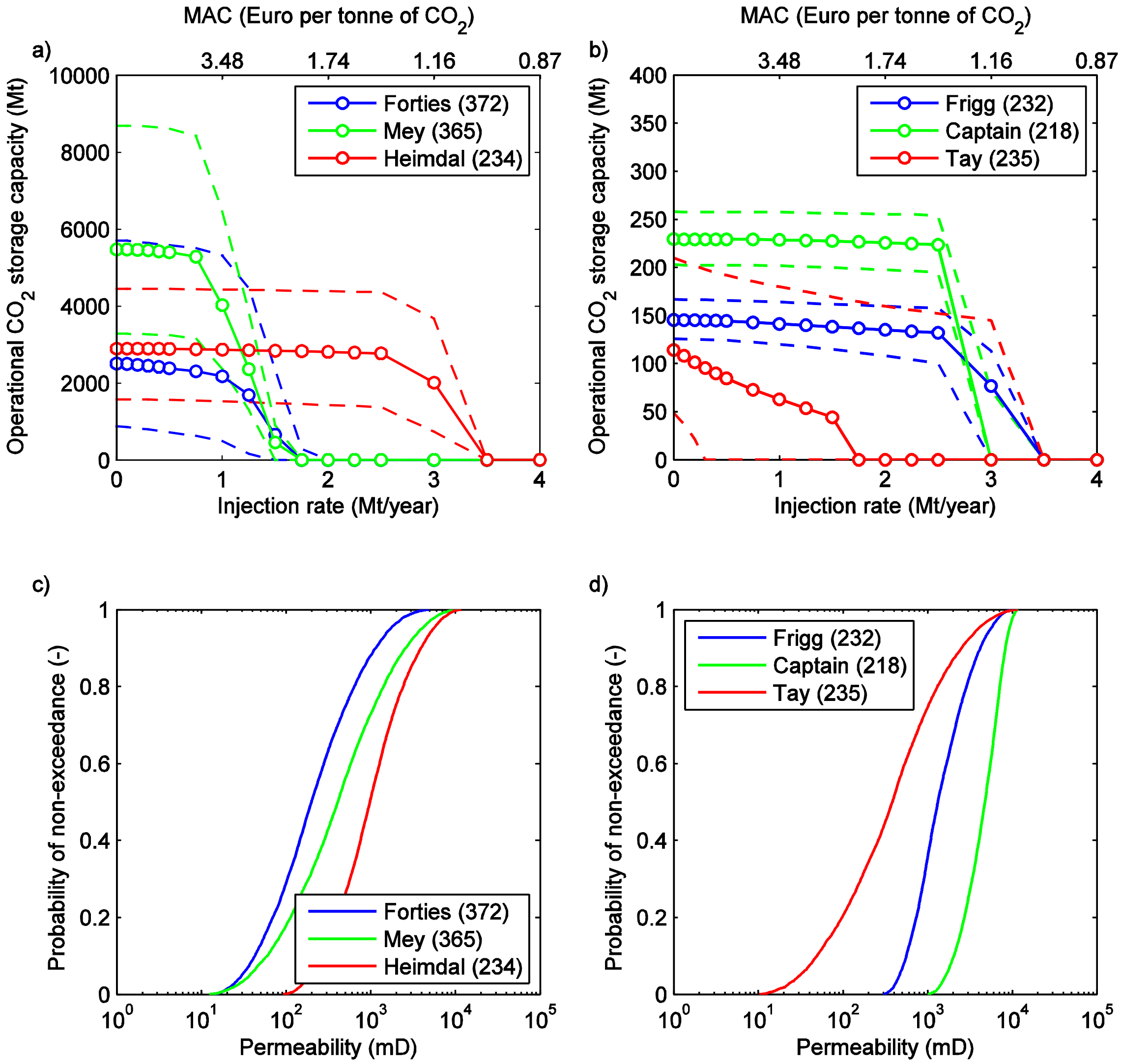


Figure 1: a and b show plots of operational CO_2 storage capacity against injection rate for six different saline formations. The name of the saline formation relates to the name of the sandstone member. The number in brackets is the associated unit identifier number in the CO_2 Stored® database. The corresponding values of maximum allowable cost (MAC) were calculated using Eq. (2) assuming a minimum injection duration of 20 years. c and d show the permeability cumulative probability distributions for each of the saline formations. The solid lines are the P50 results. The dashed lines are the P10 and P90 results.

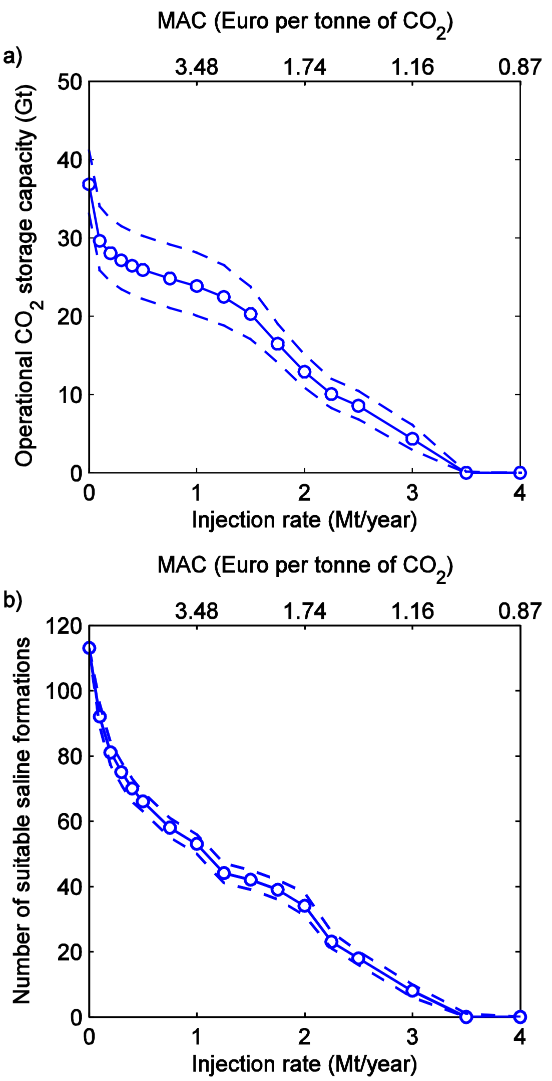
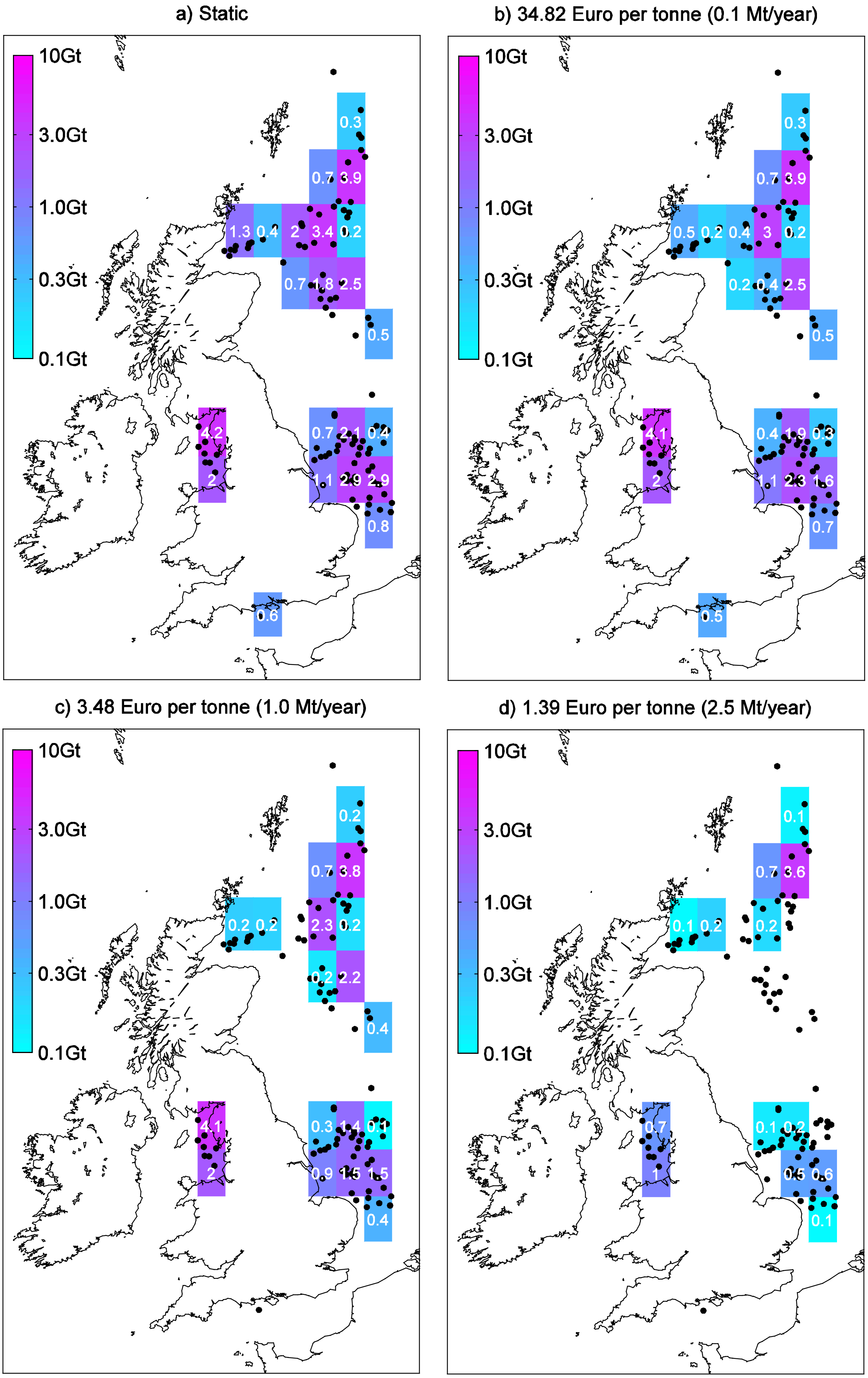


Figure 2: a shows a plot of operational CO_2 storage capacity against injection rate for all CO_2 Stored® UK offshore saline formations with centroid depths greater than 1000 m below sea bed and less than 2500 m below sea bed. b shows a corresponding plot of the number of suitable saline formations (i.e., the number of saline formations that have a non-zero operational storage capacity) against injection rate. The solid lines are the P50 results. The dashed lines are the P10 and P90 results. The corresponding values of maximum allowable cost (MAC) were calculated using Eq. (2) assuming a minimum injection duration of 20 years.



a) Static
10Gt
3.0Gt
1.0Gt
0.3Gt
0.1Gt
0.3
0.7 3.9
1.3 0.4 2 3.4 0.2
0.7 1.8 2.5
0.5
4.2
2
0.7 2.1 0.4
1.1 2.9 2.9
0.8
0.6
b) 34.82 Euro per tonne (0.1 Mt/year)
10Gt
3.0Gt
1.0Gt
0.3Gt
0.1Gt
0.3
0.7 3.9
0.5 0.2 0.4 3 0.2
0.2 0.4 2.5
0.5
4.1
2
0.4 1.9 0.3
1.1 2.3 1.6
0.7
0.5
c) 3.48 Euro per tonne (1.0 Mt/year)
10Gt
3.0Gt
1.0Gt
0.3Gt
0.1Gt
0.2
0.7 3.8
0.2 0.2 2.3 0.2
0.2 2.2
0.4
4.1
2
0.3 1.4 0.1
0.9 1.5 1.5
0.4
d) 1.39 Euro per tonne (2.5 Mt/year)
10Gt
3.0Gt
1.0Gt
0.3Gt
0.1Gt
0.1
0.7 3.6
0.1 0.2 0.2
0.7
1
0.1 0.2
0.5 0.6
0.1

619

Figure 3: A sequence of maps showing distribution of P50 operational CO_2 storage capacity across the UK. a Distribution of static capacity. b, c and d Distribution of operational storage capacity for maximum allowable cost (MAC) scenarios of 34.82, 3.48 and 1.39 € per tonne of CO_2 stored, respectively. The corresponding injection rates are 0.1 Mt/year, 1.0 Mt/year and 2.5 Mt/year, respectively. Each colour block represents the area of a standard UK Department of Energy and Climate Change quad. The white number in the quad is the storage capacity available in Gt of CO_2. The colours indicate how much storage is in the block with turquoise being the lowest and purple being the highest. The black dots show the locations of the saline formations incorporated into the study. Note that saline formations with centroids > 2500 m below sea bed or < 1000 m below sea bed were excluded.