Abstract

This paper presents a numerical simulation study of CO₂ injection into the Forties and Nelson dome structures in the North Sea. The study assumes that these structures are fully depleted of their remaining hydrocarbon and brine has replaced their pore space, and therefore the structures can be treated as saline aquifers. Under this assumption, the objective is to calculate the dynamic CO₂ storage capacity of the Forties and Nelson structures and design an injection scenario to enhance storage utilisation. In doing so, first, a detailed geological model of the dome structures and their surrounding aquifer is developed to represent the lithological facies associations and attribute them with petrophysical properties. The geological model is calibrated in terms of the surrounding aquifer support using the hydrocarbon production data. The dynamic storage capacity is subsequently estimated by numerical simulation of the two-phase (brine and CO₂) process. Key performance indicators (KPIs), such as the pressure build-up and regional mass fraction of CO₂, are used to constrain the injection scenarios that consequently result in the best capacity utilisation of the storage structures. In our model of fully brine saturated dome structures, based on specific constraints, namely <0.1% of the total gaseous CO₂ outside the dome into an upper pressure unit and 66% of the initial hydrostatic pressure as the allowable increase in the bottom-hole pressure, we obtained a dynamic capacity of 121 million tonnes for the Forties structure and 24 million tonnes for the Nelson structure. These values are subject to change when a three phase model of residual oil, gas and water is considered in simulations.

1. Introduction

The storage of carbon dioxide in depleted or mature oil or natural gas reservoirs has obvious advantages over storage in pristine aquifers where we have a limited and uncertain knowledge of the geological environment, namely their trapping potential or storage capacity. Porous rock formations that are proven traps have retained hydrocarbons for millions of years, and are potential candidates for CO₂ storage (IPCC, 2005). Moreover, this option may even be economically sustainable as it can enhance oil or gas recovery (EOR/EGR). Hence, CO₂ injection operations in mature reservoirs are the ones most likely to be implemented first, because of the additional economic benefit that will help offset the cost of CO₂ storage (Holt et al., 1995; Stevens et al., 2000).

Two reservoirs that have been considered for potential CO₂ storage through EOR in the UK Sector of the Central North Sea are the Forties and Nelson oilfields (Espie, 2001; Cawley et al., 2005; SCCS, 2009) which feature high-quality channel sands. Previously, Ketzer et al. (2005) evaluated the long term CO₂ leakage risk from the Forties reservoir assuming that it was filled with supercritical CO₂.

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They reported that the CO₂ plume would travel only a small distance in the overburden during the post-injection period. Cawley et al. (2005) reported that after the injection of CO₂ into the depleted Forties Field, CO₂ would not exceed the capillary entry pressure of the overburden. They also reported that, due to the absence of major faults, the thickness of the reservoir and very low permeability of its overburden, the Forties Field is an ideal structure for CO₂ storage. In none of these studies, however, has a storage capacity estimation of the Forties Field and the neighbouring Nelson Field been presented, where the pressure communication and fluid migration between the two structures that form a part of Forties Sandstone Member are considered in storage performance assessments.

Against this backdrop, we conduct a study in this paper, relying on a large and complex geological model of the two structures in communication with their surrounding aquifer, to estimate the dynamic capacity estimates of the Forties and Nelson fields, assuming that the structures could be treated as saline aquifers. This assumption, which may be unrealistic, is made because our three-phase simulations of the CO₂ injection into the geological model had convergence issues and required prohibitive computational power. Consequently, the results of this work may serve as crude and approximate estimates for the static and dynamic storage capacities of the Forties and Nelson structures neglecting the three-phase complexities and differences with two-phase systems, and provide dynamic capacity estimates of the storage in comparison to the reported static estimates for the same structures. Examples in the literature of presented estimates are SCCS (2009) that reported 138 million tonnes CO₂ capacity for the Forties oilfield by the CO₂-EOR process. Assuming a range of 0.2%–2% storage efficiency, they reported storage capacities of 886–8,856 million tonnes CO₂. Elsewhere, Espie (2001) reported that at least 75 million tonnes of CO₂ could be stored underground as a result of EOR in the Forties Field, with further potential if storage was continued for its own sake after EOR.

In this paper we will use the numerical simulation as the most sophisticated method of estimating dynamic CO₂-storage capacity. Examples of dynamic methods are decline-curve analysis (Frailey, 2009), material balance (Mathias et al., 2009; Zhou et al., 2008), and reservoir simulation-based approaches (e.g., Doughty and Pruess, 2004; Kumar et al. 2004; Ennis-King and Paterson, 2005; Ozah et al., 2005; Flett et al., 2007; Yamamoto et al., 2009 and Liao et al., 2014). A full review of the dynamic storage capacity estimation in comparison with static methods is presented in Bachu et al. (2015). The numerical methods have the advantage of being able to take into account the heterogeneity of the storage site and trapping of CO₂ by various storage mechanisms that are involved in the storage process. They also account for the physical processes which are important for CO₂ storage, such as the build-up of pressure in the near-well region and throughout the storage site, and migration of CO₂ by advection and buoyancy. Birkholzer et al. (2015) thoroughly surveyed pressure build-up issue and its direct implications on utilizing the storage capacity.

We will use the pressure build-up and migration that may critically affect the storage capacity of aquifer structures to define key performance indicators (KPI’s) to assess the injection process as well as to define constrained injection strategies. We will use a novel injectivity-index-weighted dynamic apportioning of rate between a series of fixed injection wells. Injectivity and its dynamic variations are assumed as important factors to be considered in the optimal design of storage capacity utilization (van der Meer and Egberts, 2008; Burton et al., 2008; van der Meer and Yavuz, 2009). The methodology proposed here takes into account effects of the geological model properties on the wells’ injectivities and the inflow performances, and dynamic variations of injectivities. Migration and pressure build-up control measures are also simultaneously applied to produce a set of dynamically varying injection rates so that an optimal injection scenario can be designed.

Outline: In the sections that follow, first we describe the geological model of the dome structures in Section 2 (with extra information about the geological settings and model construction in the
Appendix). Next in Section 3, a calibration exercise is presented in which the aquifer support of the study area is adjusted using the pressure behaviour of the hydrocarbon reservoirs. In Section 4, the KPI’s are defined and the methodology to extract injection rates based on the dynamically varying injectivity of the injection wells is presented. The results are given in Section 5 and conclusions and future work in Section 6.

2. Study area and geological model

The study area is located on the Forties-Montrose High in the UK Central North Sea (Figure 1a). The 3D model has been built around an area that includes the Forties and Nelson hydrocarbon fields that are four-way dip closed structures containing sandstone reservoirs capped by a thick mudstone-dominated seal. There are four main production platforms, evenly spaced over the area of the Forties field: Forties Alpha (FA), Bravo (FB), Charlie (FC) and Delta (FD), and an auxiliary platform Forties Echo (FE) (Figure 1b). There is only one platform for the Nelson reservoir which is referred to as N in DECC’s database for production wells in the North Sea (DECC, 2007). The depth map of the top surface of the 3D model is shown in Figure 1c.

The hydrocarbon reservoirs of the Forties and Nelson fields are submarine fan deposits contained in the Upper Paleocene/ Lower Eocene Sele Formation and overlain by Lower Eocene shales (Hughes et al., 1990; Whyatt et al., 1992). The reservoirs are located in the proximal inner (interbedded sand/shale) to middle (mainly massive sand) fan region (Hughes et al., 1990) and are mostly channelised and characterised by high net to gross ratios, good porosities and high permeabilities (Hempton et al., 2005). Detailed geological modelling of the Forties and Nelson hydrocarbon fields in the UK sector of the North Sea has been reported by Kulpeycz and van Geuns (1990) and Kunka et al. (2003).

The geological model developed in this study broadly captures and represents the heterogeneities present within what is a very complex submarine fan environment. The fan system within the two fields comprises the main hydrocarbon producing fairways: large amalgamated stacked channel systems of the Late Paleocene/ Early Eocene Forties Sandstone Member within four-way dip-closed anticlinal structures. Along with the channels are the associated channel margins and interchannel areas. The varying relative dominance and position of the different parts of the submarine fan system through time resulted in a high degree of lateral and vertical variation. This is represented in the lithologies found in the system and their associated petrophysical parameters.

The structural zonation schemes in each of the fields have been unified and extended out with the field areas (Table 1). The geological model consists of 5 reservoir Zones (E, F, H, J and K), capped by a seal (Zones M and L). The reservoirs overlie a field-wide discontinuity between Zones E and D, so that Zone D is mostly (for Forties) or entirely (for Nelson) under the water-oil-contact. The geological model contains a field-wide permeability barrier between Zones H and J. This barrier is also referred to as Charlie Shale that produces a notable pressure discontinuity over the west and centre of the Forties field but is thin and discontinuous in the east and south-east of the field. In the east over the Nelson Field the barrier forms part of the top seal, therefore the caprock is thicker for Nelson than Forties. Consequently, most of the Forties Field and a small part of the Nelson Field are divided into two pressure units: Zones J and K (upper pressure unit), and Zones E, F and H (lower pressure unit). Other partially extensive barriers (notably between Zones E and F, and between Zones F and H) are modelled by vertical permeability multipliers. As Zone D is mostly or entirely below the water-oil contact lines of both reservoirs, and Zones M and L form a seal for Forties, only Zones K, J, H, E and F are considered in the study since they include the reservoir units.
Figure 1. (a) Central North Sea region showing the distribution of the Forties Sandstone Member, known hydrocarbon accumulations in the member (Robertson et al., 2013), and three Area Types as defined in the Appendix. The study area is shown by a neon green template. (b) The location of the production platforms in Forties: Forties Alpha (FA), Forties Bravo (FB), Forties Charlie (FC), Forties Delta (FD) and auxiliary Forties Echo (FE), and single platform in Nelson. The wells that are scattered across the region have been used for water injection. (c) The elevation map of the top surface of the study area and the wells used for injection in this study namely 21/10-1 at FA, 21/10-837 at FB, 21/10-C22 at FC, 21/10-D49 at FD, and 21/11-N1 at N. The vertical direction is exaggerated by a factor of 10.
### Table 1. Unification of geological model zonation in Forties by Wills (1991) and Nelson by Kunka et al. (2003)

<table>
<thead>
<tr>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone M (caprock of Sele Formation)</td>
<td>Unit M</td>
<td>mudstone</td>
<td>37</td>
<td></td>
</tr>
<tr>
<td>Zone L (caprock)</td>
<td>Unit L</td>
<td>Partially present and very thin over Nelson</td>
<td>mudstone</td>
<td>8</td>
</tr>
<tr>
<td>Zone K (upper pressure unit)</td>
<td>Unit K</td>
<td>Partially present and very thin over Nelson</td>
<td>thick bedded sandstone and interbedded sandstone and mudstone</td>
<td>14</td>
</tr>
<tr>
<td>Zone J (upper pressure unit)</td>
<td>Unit J</td>
<td>Partially present and very thin over Nelson</td>
<td>thick bedded sandstone and interbedded sandstone and mudstone</td>
<td>44</td>
</tr>
<tr>
<td>Field-wide pressure discontinuity (Charlie Shale)</td>
<td></td>
<td></td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Zone H (lower pressure unit)</td>
<td>Unit H</td>
<td>Zone 5</td>
<td>thick bedded sandstone, and interbedded sandstone and mudstone</td>
<td>22</td>
</tr>
<tr>
<td>Zone F (lower pressure unit)</td>
<td>Unit F</td>
<td>Zone 4</td>
<td></td>
<td>39</td>
</tr>
<tr>
<td>Zone E (lower pressure unit)</td>
<td>Unit E</td>
<td>Zone 3</td>
<td></td>
<td>40</td>
</tr>
<tr>
<td>Field-wide pressure discontinuity</td>
<td></td>
<td></td>
<td></td>
<td>25</td>
</tr>
<tr>
<td>Zone D (below oil-water contact)</td>
<td>Unit D</td>
<td>Zones 1 &amp; 2</td>
<td>succession of thin bioturbated sandstones and mud-rich conglomerate</td>
<td>123</td>
</tr>
</tbody>
</table>

The positions of the channels in each zone and the extent of the Forties and Nelson fields that lay inside each of these zones are illustrated in Figure 2. The extent of storage domes is determined from topography and the original oil-water contact of the reservoir.

Figure 2 also shows the regionalisation of the different zones of the model based on whether they are located inside or outside the structure domes. In order to set this up, we used the horizon surfaces of the different zones in the model and the initial water-oil contact planes of the Forties and Nelson reservoirs, located at 2217 m and 2270 m depth respectively.
The attribution of the geological model with petrophysical properties, namely porosity, permeability and net-to-gross (NTG) ratio, was carried out using Gaussian random functions. The ranges of values used, including their mean values, are summarised in Table 2 for the different geological facies associations. Some of these values are based on generalisations from the literature such as Kunka et al. (2003) and Wills (1991), and in absence of data, average values were assumed by the authors.

Table 2. Petrophysical properties for different facies types from Kunka et al. (2003) and Wills (1991) and well log analyses; values indicated as mean (minimum, maximum). For additional information about different facies mentioned in this table please refer to the Appendix.

<table>
<thead>
<tr>
<th>Petrophysical property</th>
<th>Channel sands</th>
<th>Basal lags (low permeability)</th>
<th>Basal lags (high permeability)</th>
<th>Shale doggers</th>
<th>Interchannel (Slump debris and Mudstones)</th>
<th>Slump bodies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (%)</td>
<td>25 (21, 38)</td>
<td>25 (21, 38)</td>
<td>25 (21, 38)</td>
<td>&lt;12</td>
<td>24.6 (3, 32.9)</td>
<td>13 (3, 32.9)</td>
</tr>
<tr>
<td>Horizontal Permeability (mD)</td>
<td>376 (31, 1,610)</td>
<td>376 (31, 1,610)</td>
<td>376 (31, 1,610)</td>
<td>&lt;1</td>
<td>163 (0.01, 1,769)</td>
<td>50 (0.01, 1,769)</td>
</tr>
<tr>
<td>Vertical Permeability (Multiplier)</td>
<td>0.1</td>
<td>0.01</td>
<td>0.1</td>
<td>1</td>
<td>0.001-0.01</td>
<td>0.001-0.01</td>
</tr>
<tr>
<td>NTG</td>
<td>0.72 (0.21, 1)</td>
<td>0.72 (0.21, 1)</td>
<td>0.72 (0.21, 1)</td>
<td>0.21 (0.21, 1)</td>
<td>0.33 (0.11, 0.89)</td>
<td>0.11 (0.11, 0.89)</td>
</tr>
</tbody>
</table>
A realisation was generated based on the above-mentioned properties at a grid resolution of 100 m $\times$ 100 m $\times$ 2 m. The profiles of horizontal and vertical permeability, porosity and net-to-gross ratio are shown in Figure 3. The same realisation with the specified resolution is used for flow modelling.

**Figure 3.** (a) Horizontal permeability (millidarcy), (b) vertical permeability (millidarcy), (c) porosity, and (d) net-to-gross ratio for top of Zone E.
3. Simulation of hydrocarbon production for calibrating the model

In this section the aquifer model is calibrated using historical hydrocarbon production and water injection data from the DECC database (DECC, 2007), as well as the historical pressure data found in the literature. Some of the properties of the hydrocarbon and resident water derived from literature for the two oil fields are summarised in Table 3. The oil-gas and water-gas relative permeability curves are derived from Cawley et al. (2005) who studied an enhanced oil recovery using CO₂ at a segment of the Forties Field. It is assumed these curves are applicable for the fluids across the entire domain of the study area in this work.

| Table 3. Reservoir fluid properties from Wills (1991), and Kunka et al. (2003). |
|---------------------------------|--------|--------|
| **Hydrocarbon**                 | **Forties** | **Nelson** |
| Initial oil saturation \( S_o \) | 0.85   | 0.80   |
| Initial oil in place \( V_{oi} \) (standard million m³ or sm³) | 690    | 125    |
| Formation volume factor \( B_o \) (reservoir m³/standard m³ or rm³/sm³) | 1.24–1.32 | 1.36 |
| Initial oil in place \( V_{oi} \) (reservoir million m³) \[ V_{oi} = V_{oi} \times B_o \] | 883    | 170    |
| Dome volume above water-oil contact \( V_{po}/S_o \) | 1,038  | 212    |
| Recovery factor by 2013          | 0.62   | 0.58   |
| **Formation water**             |        |        |
| Salinity (ppm of NaCl)           | 55,500 | 84,000 |
| Resistivity (ohm m)              | 0.034  | N/A    |
| **Reservoir conditions**         |        |        |
| Temperature (°C)                 | 96 at 2175 | 107 at 2255 m |
| Initial pressure (bar)           | 222 at 2175 m | 229     |
| Oil-water contact                | 2217 m | 2270 m |

In addition to the data above, we assume formation brine has a coefficient of isothermal compressibility of \( 3.5 \times 10^{-5} \text{bar}^{-1} \) and rock has a coefficient of isothermal compressibility of \( 4.5 \times 10^{-5} \text{bar}^{-1} \).

An objective of the model calibration is to determine the pore volume multiplier (PVM) that will be used in the simulations to establish the boundary conditions accounting for the pressure support from the surrounding aquifer system. PVM applied on the boundary grid blocks effectively enlarges the domain, which in turn has a direct effect on the pressure behaviour. Obviously, the larger the value of the multiplier, the less the pressure depletion during production will be. In order to establish a reasonable value, the data for pressure decline at start of the production and the pressure build-up at start of the water injection are also used.

According to Brand et al. (1996) and Wills (1991), in the first 5 years after production started (by start of 1981), the pressure in the oil bearing sandstone layers of Forties declined by 55-70 bar below the original level. Brand et al. (1996) provided pressure depletion profiles in two sandstone regions of Forties (Zones E, F and H in the centre and east and Zones J and K in the west).

Permeability restrictions exist between the sand bodies of the field (south-east Forties) that cause significant pressure differences between them (Brand et al., 1996).

With the aquifer support having come into effect, coupled with the increasing water injection by 1994, the reservoir pressure rose back to around 14 bar below the original hydrostatic level.

Moreover, Simpson and Paige (1991) report that the Forties reservoir pressure was maintained by basal aquifer influx initially, prior to the supplementation of peripheral seawater injection. For the Nelson Field, it is reported by Kunka et al. (2003) that by July 1997, 3 years after the production started, the pressure depletion was similar to Forties, around 55-70 bar below the initial level. Here,
it is assumed that the pressure drop would be compensated by a combination of the basal aquifer support and peripheral seawater injection over time.

Based on the above information and assumptions, the PVM is determined by matching the simulated regional pressures with pressure behaviour of the Forties and Nelson oilfields. The target is a post-production average pressure decline of around 70 bar over the oilfield regions that can be compensated later on during the simulation. The multiplier of \( PVM = 20 \) that leads to a reasonable behaviour of the field pressure in the production stage is used for the \( \text{CO}_2 \) injection simulations. This multiplier applied on the boundary blocks increased the formation pore volume in the whole system from 8,552 million \( \text{rm}^3 \) to 42,548 million \( \text{rm}^3 \).

The yearly cumulative oil and water production from Forties and Nelson are shown in Figure 4(a) and Figure 4(b). Except for the overestimations of water production at some stages, the graphs show a good agreement between the simulation results and the actual data. The average pressure for areas including Forties and Nelson are shown in Figure 4(c). A post-production pressure decline of up to 70 bar is observed that was later compensated for by water injection and water influx from the boundaries. It is noted that the pressure profiles from literature and simulation do not accurately represent the true average pressures from the geological units; however, the trends are in reasonable agreement. Another reason for the observed discrepancy and delayed pressure recovery of our model against the existing data can be probably linked to the insufficiency of considering PVM as the only parameter for model calibration. A \( PVM > 20 \) would create pressure profiles with too small reduction during initial years, whereas a \( PVM < 20 \) result in pressure profiles with too large reduction during initial years and too little post-water-injection increase. In conclusion, based on a reasonable agreement between data and our model, the assumption will be made that the pressure has been restored to the initial hydrostatic level prior to \( \text{CO}_2 \) injection.
Figure 4. (a) The yearly oil production rates from the Forties and Nelson oilfields, (b) the yearly water production rates from the Forties and Nelson oilfields, simulation results compared to the actual data from DECC (2013). (c) The pressure depletion profiles from the hydrocarbon production simulation. Also shown are the field data for Charlie Sand (mostly coinciding with Zones J and K) and Main Sand (mostly coinciding with E, F and H) from Brand et al. (1996).
4. Dynamic capacity calculation

4.1 Definitions of the key performance indicators (KPIs)

To assess injection scenarios, a number of KPIs are defined and calculated throughout the injection and post-injection periods. These parameters are:

1) Well bottomhole pressure build-up ratio:

\[ r_{p,W}^t = \frac{p_{b,h,W}^t}{p_{h,i}^t} \]  

where \( p_{b,h,W}^t \) represents the well bottomhole pressure of a well \( W \) at a simulation time \( t \), \( p_{h,i}^t \) represents the hydrostatic pressure at initial time \( t^0 \) of the block \( i \) in the 100 m × 100 m × 2 m grid. Therefore \( r_{p,W}^t \) is the ratio of the well bottomhole pressure over the initial hydrostatic pressure of the perforated depth. This measure indicates the local pressure increase of the system due to \( \text{CO}_2 \) injection and should be limited to some certain values according to the fracture pressure avoidance constraint.

2) Mass fraction of \( \text{CO}_2 \) in various regions of the domain:

\[ x_{m,R}^t = \frac{m_{\text{R},CO_2}^t}{m_{CO_2}^t} \]  

where \( m_{\text{R},CO_2}^t \) represents the mass of \( \text{CO}_2 \) present in a region \( R \) at a simulation time \( t \) and \( m_{CO_2}^t \) represents the total mass of \( \text{CO}_2 \) injected into the system by simulation time \( t \). Therefore \( x_{m,R}^t \) is the mass fraction of injected \( \text{CO}_2 \) in region \( R \) at simulation time \( t \).

To help track the \( \text{CO}_2 \) plume movement and spillage outside the storage dome, the model domain is divided into four control regions:

- the Forties dome: Region 1
- the Nelson dome: Region 2
- areas lying outside the domes in Zones J and K (Forties upper pressure unit): Region 3
- areas lying outside the domes in Zone E, F and H (Forties lower pressure unit): Region 4

We define:

\[ x_{m,1}^t = \frac{m_{\text{gaseous \, CO}_2, R1}^t + m_{\text{dissolved \, CO}_2, R1}^t}{m_{CO_2}^t} \]
\[ x_{m,2}^t = \frac{m_{\text{gaseous \, CO}_2, R2}^t + m_{\text{dissolved \, CO}_2, R2}^t}{m_{CO_2}^t} \]
\[ x_{m,3}^t = \frac{m_{\text{gaseous \, CO}_2, R3}^t}{m_{CO_2}^t} \]
\[ x_{m,4}^t = \frac{m_{\text{gaseous \, CO}_2, R4}^t}{m_{CO_2}^t} \]

where \( x_{m,1}^t \) and \( x_{m,2}^t \) indicate the level of containment of \( \text{CO}_2 \) inside the Forties and Nelson structures, and \( x_{m,3}^t \) and \( x_{m,4}^t \) indicate the gaseous \( \text{CO}_2 \) remained outside of the dome structures at time \( t \). Only the gaseous portion of \( \text{CO}_2 \) is considered in \( x_{m,3}^t \) and \( x_{m,4}^t \), because...
it is assumed that the dissolved CO₂ implies less risk of leakage to the surface from regions outside the dome structures. Therefore $x_{m,3}^	ext{c}$ and $x_{m,4}^	ext{c}$ cannot be used for mass balance calculations, and they are defined as such only for leakage potential. It should be noted that Region 3 lies in Zones J and K (the part of Forties upper pressure unit shown in yellow in Figure 2b), which is penetrated by a large number of abandoned wells. This, together with the fact that Zone J is also in immediate contact with the caprock, makes this region prone to risk of CO₂ leakage through abandoned wells and the caprock outside of the dome. Therefore, reducing $x_{m,3}^	ext{c}$ must be one objective of the injection design.

3) Fraction of capacity utilised:

$$e_{V,R}^c = \frac{V_{CO_2,R}^t}{PV_R} \tag{4}$$

where $V_{CO_2,R}^t$ represents the summation of gaseous and aqueous volumes of CO₂ at reservoir conditions in a region $R$ at a simulation time $t$ and $PV_R$ represents the pore volume of the region $R$ at reservoir conditions. Therefore $e_{V,R}^c$ is the fraction of capacity of the region $R$ utilised at simulation time $t$. Obviously, the larger this value is, the more efficient the storage operation is. It should be noted that this metric should not be confused by commonly used “storage efficiency” defined by van der Meer (1995) as “the ratio between the maximum storage volume and the actual injected volume.” Here this metric is calculated in terms of the volume of CO₂ injected in the section of the reservoir formation that is inside the perimeter of the reservoirs’ boundaries rather than the whole aquifer volume and therefore the values will be higher than the storage efficiency values because the denominator is much smaller.

In our model, $PV_R$ for Region 1 is 1,042 million $\text{rm}^3$ (compared to 1,038 million $\text{rm}^3$ in Table 3 for Forties dome), for Region 2, $PV_R$ is 219 million $\text{rm}^3$ (compared to 212 million $\text{rm}^3$ in Table 3 for Nelson dome), for Region 3, $PV_R$ is 4,435 million $\text{rm}^3$ and for Region 4, $PV_R$ is 36,852 million $\text{rm}^3$, note that PVM acts only on the pore volume of the boundary blocks of Regions 3 and 4. The discrepancies between the pore volumes of our model and the actual reservoirs can be attributed to the stratigraphical inaccuracies.

### 4.2 Definitions of constrained injection scenarios

For calculating the dynamic capacity of the Forties Field and at the same time utilising its storage capacity optimally, four vertical injection wells were located on the main platforms in Forties and one was placed on the Nelson Field platform. The injection pressure is constrained as not to exceed 0.9 multiplied by the fracture pressure of the injection depth:

$$p_{bh,W}^f \leq 0.9 \times p_{f,W} $$

$$r_{p,w}^{f} = \frac{p_{f,w}^{f} \times (g_f/g_h)p_{h,b}^{i}}{p_{f,w}^{r} \times r_{p,w}^{o}} $$

$$r_{p,w}^{r} \leq 0.9 \times g_f/g_h \tag{5}$$

where $p_{f,W}$ is the fracture pressure at perforation depth of well $W$, $g_f$ is the fracture gradient of the system, $g_h$ is the hydrostatic gradient of the system, and $p_{h,b}^{i}$ is the initial hydrostatic pressure (defined at the centre of the 100 m x 100 m x 2 m gridblock, $i$) at a reference depth of top of Zone H where bottomhole pressure of well $W$ is also calculated. All the wells are assumed to be 0.3048 metres in diameter, the fracture gradient for the Forties Sandstone Member is assumed 1 psi/ft or 0.226 bar/m (Cawley at al., 2005), and the hydrostatic gradient is assumed 0.54 psi/ft or 0.122 bar/m. Therefore, the pressure constraint is reduced to:

$$r_{p,w}^{f} \leq 1.66 \tag{6}$$
For the five wells of the system, at initial time and at top of Zone H just below the Charlie Shale, we have \( p_{h,FA}^0 = 248 \) bar, \( p_{h,FB}^0 = 245 \) bar, \( p_{h,FC}^0 = 236 \) bar, \( p_{h,FD}^0 = 245 \) bar and \( p_{h,N}^0 = 241 \) bar.

To implement the migration constraint, we define a total target injection rate of \( Q_{\text{inj}}^{\text{total}} \) (million tonnes per annum, hereafter denoted as \( \text{MTY}^{-1} \)) to be apportioned between five injection wells based on a time varying weight of injectivity index of each well with respect to sum of all wells’ injectivity indices, so that:

\[
Q_{\text{inj},W}^t = \begin{cases} 
 f^{-1} \left( \frac{Q_{\text{inj}}^{\text{total}} \times \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right)}{\sum_{W \in W1} \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right)} \right) + (1 - f^{-1}) \frac{Q_{\text{inj}}^{\text{total}} \times \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right)}{\sum_{W \in W2} \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right)}, & W \in W2 \\
 f^{-1} \left( \frac{Q_{\text{inj}}^{\text{total}} \times \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right)}{\sum_{W \in W1} \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right)} \right), & W = FC 
\end{cases}
\]

(7)

\[
f^{-1} = \begin{cases} 
 1, & (x_{m,1}^{t-1} \times m_{CO2}^{t-1}) \leq 0.1 \text{ million tonne} \\
 0, & (x_{m,3}^{t-1} \times m_{CO2}^{t-1}) > 0.1 \text{ million tonne} 
\end{cases}
\]

(8)

where:

- \( Q_{\text{inj},W}^t \) is the “target” injection rate of well \( W \) at time \( t \), actual injection rate can be lower when the bottomhole pressure constraint for the well of interest is violated,
- \( I_{W,c}^{t-1} \) is the injectivity index of well \( W \) at connection (perforation) \( c \) and at time \( t - 1 \), calculated as \( I_{W,c}^{t-1} = Q_{\text{inj},W}^{t-1} / \left( p_{bh,W,c}^{t-1} - p_e^{t-1} \right) \), where \( p_{bh,W,c}^{t-1} \) is the bottomhole pressure of well \( W \), at depth of connection \( c \) and at time \( t - 1 \), and \( p_e^{t-1} \) is the pressure at the vicinity of connection \( c \) of well \( W \) at time \( t - 1 \),
- \( N_W \) and \( N_c \) are the number of wells and number of connections for each well,
- \( W1 \) is a set of wells including all five injection wells,
- \( W2 \) is a set of all wells except for FC,
- \( f^{-1} \) is a multiplier that is 1 when the amount of gaseous CO\(_2\) in Region 3 has not exceeded the threshold of 0.1 million tonne. As soon as this threshold is exceeded, \( f^{-1} \) is set to zero
- \( x_{m,3}^{t-1} \) and \( m_{CO2}^{t-1} \) are as defined previously, the fraction of gaseous CO\(_2\) in Region 3 and the total amount of CO\(_2\) (in moles) of gaseous and aqueous CO\(_2\) in all regions at time \( t - 1 \).

Above formulation apportions, initially, the total amount of available injection gas, to all five wells proportional to their injectivity indices by the vector of \( Q_{\text{inj}}^{\text{total}} \times \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right) / \left( \sum_{W \in W1} \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right) \right) \). However, since well FC contributes significantly to the migration of CO\(_2\) outside the domes through Region 3 (the risk-prone region), this well is shut off when the migration constraint is violated (\( f^{-1} = 0 \) and the total amount of gas is divided between other wells by the vector of \( Q_{\text{inj}}^{\text{total}} \times \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right) / \left( \sum_{W \in W2} \left( \sum_{c=1}^{N_c} I_{W,c}^{t-1} \right) \right) \)). This approach ensures maximum injection of CO\(_2\) into the two dome structures with the specific pressure and migration constraints honoured.

The question in this work can be summarised as:

What is the maximum amount of CO\(_2\) that we can inject (actual cumulative injection denoted by \( q_{\text{inj}}^{\text{cumul}} \)) into the two structures by five available injection wells so that:

- the pressure constraint is not violated at any time;
• a specific threshold of 0.1 million tonne of gaseous CO\textsubscript{2} is the maximum permissible amount that can migrate into the Zones J and K outside the dome structures (Region 3) of the model.

A range of $Q_{\text{inj}}^{\text{total}}$ is prescribed in a 30-year injection period. The simulations are continued for a 50-year post-injection monitoring period to record KPIs. The simulations are conducted on a HP ProLiant Server with 12-core processor, allowing parallel simulations at the time with Schlumberger’s ECLIPSE E300 compositional simulator with CO2STORE option for CO\textsubscript{2} storage in saline aquifers. Each simulation takes about 17,849 seconds on the server.

5. Results

In order to find the pressure and migration constrained injection strategy, we conduct 20 simulations of $Q_{\text{inj}}^{\text{total}}$ ranging from 1 to 20 MTY\textsuperscript{-1}. The actual total injected CO\textsubscript{2} ($q_{\text{inj}}^{\text{cumul}}$) is shown in Figure 5(a) for increasing $Q_{\text{inj}}^{\text{total}}$. It is observed that when $Q_{\text{inj}}^{\text{total}} = 12$ MTY\textsuperscript{-1}, the pressure constraint has led to $q_{\text{inj}}^{\text{cumul}} < (30 \text{ years} \times Q_{\text{inj}}^{\text{total}})$, thereby actual injected gas is less than the target injection. Figure 5(b) shows the maximum amount of spilled gaseous and dissolved CO\textsubscript{2} in Region 3 and 4 or $x_{m,R}^{30 \text{ years}} \times n_{\text{CO}_2}^{30 \text{ years}}$ in million tonnes. For this figure, $Q_{\text{inj}}^{\text{total}} = 8$ MTY\textsuperscript{-1} is a threshold injection rate above which the specifically defined threshold of 0.1 million tonnes CO\textsubscript{2} in Region 3 is violated. This is despite the fact that the injection strategy switches off the injection at FC to prevent the migration constraint being violated. In other words FA, FB and FD (only FB as will be shown later) are contributing to the migration for $Q_{\text{inj}}^{\text{total}} > 8$ MTY\textsuperscript{-1}. In Figure 5(b), we also showed the dissolved CO\textsubscript{2} versus $Q_{\text{inj}}^{\text{total}}$ for Region 3 and Region 4 by end of the injection period.

Figure 5(c) shows the total actual injected gas for each well per $Q_{\text{inj}}^{\text{total}}$. The injectivity-index-based apportioning of rate chooses FC as the most suitable injection location between all five wells, and after FC is shut early in the simulation (for $Q_{\text{inj}}^{\text{total}} = 4$ MTY\textsuperscript{-1} and higher), N becomes the most suitable location. Then at $Q_{\text{inj}}^{\text{total}} = 12$ MTY\textsuperscript{-1} and higher, N initially gets higher proportions of injection, but because $Q_{\text{inj}}^{\text{total}}$ is high, N violates the pressure constraint (Figure 5d) and therefore its injection rate is reduced so that by $Q_{\text{inj}}^{\text{total}} = 16$ MTY\textsuperscript{-1}, FB becomes the well with the highest cumulative gas injection of the system, despite the fact that FB itself reaches to the threshold of $r_{p,W}^{f} = 1.66$ sometime in the simulation. For all the simulations, $r_{p,W}^{f}$ at 30 years for each well and for each $Q_{\text{inj}}^{\text{total}}$ is shown in Figure 5(d).

In our 3D model, FA and FD have relatively low injectivity indices and therefore they are not favourable for injection. The low injectivity is also manifested for high $Q_{\text{inj}}^{\text{total}}$ where even small proportions of injection gas lead to FA and FD reaching $r_{p,W}^{f} = 1.66$ during the simulation (Figure 5d). A favourable location of FC (next to the Forties spill point to Zones J and K), and then FB which is located away from the spill point to Zones J and K and away from abrupt discontinuity of Zones J and K towards the east outweigh the injectivity of FA and FD.
Figure 5. (a) Cumulative (actual) gas injected versus $Q_{inj}^{total}$, (b) the amount of CO$_2$ in gaseous phase in Region 3 versus $Q_{inj}^{total}$, (c) Cumulative (actual) gas injected for each well versus $Q_{inj}^{total}$, and (d) the ratio of pressure increase at year 30 for each well versus $Q_{inj}^{total}$.

Figure 6 shows the profiles of gaseous CO$_2$ ($x_{m,R}^{t=30 \text{ years}} \times m_{CO2}^{t=30 \text{ years}}$) and fraction of capacity utilised by increase in $Q_{inj}^{total}$. For Nelson we reach plateaus for both quantities at $Q_{inj}^{total} = 14$ MTY$^{-1}$. Therefore increase in $Q_{inj}^{total}$ does not necessarily lead to increase in fraction of capacity utilised.

Figure 6(a) shows that Forties dome is capable of accommodating around 121 million tonnes of CO$_2$ applying the selected injection rate of $Q_{inj}^{total} = 8$ MTY$^{-1}$ (corresponding to a total amount of injection of 240 million tonnes). For Nelson the value is 24 million tonnes. Therefore, based on our migration constraint of less than 0.1 million tonnes of gaseous CO$_2$ in Region 3 (the pressure constraint is not limiting injection for $Q_{inj}^{total} = 8$ MTY$^{-1}$), the dynamic capacities of Forties and Nelson stand at 121 million tonnes and 24 million tonnes respectively. Corresponding fraction of capacity utilised for Forties and Nelson are shown in Figure 6(b), where at $Q_{inj}^{total} = 8$ MTY$^{-1}$, both $x_{V,R1}^{t=30 \text{ years}}$ and $x_{V,R2}^{t=30 \text{ years}}$ curves intersect each other at 0.147.
Figure 6. (a) The amount of CO$_2$ in gaseous phase at Regions 1 and 2 versus \(Q_{\text{inj}}^{\text{total}}\), and (b) the volumetric storage efficiency for Regions 1 and 2 (Forties and Nelson dome structures, respectively) at year 30 versus \(Q_{\text{inj}}^{\text{total}}\).

To visualise the distribution of CO$_2$ in the 3D model, for monitoring purposes we additionally simulate a 200 year post-injection period using \(Q_{\text{inj}}^{\text{total}} = 8\) MTY$^{-1}$ and its corresponding injection strategy with the well injection rates shown in Figure 7(a) and resultant bottomhole pressure profiles in Figure 7(b) for the 30-year injection period.

Figure 7. (a) The dynamically varying injection rates for the five injection wells corresponding to \(Q_{\text{inj}}^{\text{total}} = 8\) MTY$^{-1}$ for the 30-year injection period. FC is shut for year 10 because of the migration constraint. (b) \(P_{\text{bh},W}\) for the five injection wells corresponding to \(Q_{\text{inj}}^{\text{total}} = 8\) MTY$^{-1}$ for the 30-year injection period. None of the wells are affected by the pressure constraint at this \(Q_{\text{inj}}^{\text{total}}\).

Figure 8(a) shows the spread of CO$_2$ gas saturation after 230 years of simulation for all regions of the 3D model. We filtered out the blocks that have less than 0.01 gas saturation. Figure 8(b) shows the extent of gaseous CO$_2$ \((S_g > 0.01)\) outside the dome structures in Region 3 only. Clearly there is only a negligible amount of gas in Region 3. Figure 8(c) shows the extent of gaseous CO$_2$ \((S_g > 0.01)\) outside the dome structures in Region 4 only. Underneath the Nelson dome, a significant amount of gas has been stored, because the Nelson well, N, has been on operation with a high injection rate after well FC is shut.
Figure 8. The gas saturation ($S_g$) distribution 200 years after CO$_2$ injection stopped. (a) The distribution for all blocks with $S_g > 0.01$, (b) the distribution for blocks belonging to Region 3 only with $S_g > 0.01$, and (c) the distribution for blocks belonging to Region 4 only with $S_g > 0.01$. 
6. Conclusions and future work

The authors have constructed a detailed geological model that encompasses the Forties and Nelson dome structures and the surrounding aquifer system located in the UK Central North Sea. Historical data for hydrocarbon production was used to calibrate the model in terms of the aquifer support for pressure by scaling the pore volumes at the boundaries of the model. A number of key performance indicators for CO₂ storage including the ratio of pressure increase, regional mass fractions, and fraction of capacity utilised alongside the injection strategy constrained by both pressure and migration were defined. It was assumed that the structures are fully saturated with brine and consequently our simulations are based on CO₂ storage in saline aquifers.

The injection simulation results for a range of input total injection target rates were used to extract the dynamically varying injection rates weighted by the injectivity indices of the wells. The injection scenarios also honoured the pressure and migration constraints for five wells belonging to the five platforms of the two structures. It was shown that, based on the specific threshold of well bottomhole pressures to stay below 1.66 times the initial hydrostatic pressure, and the migration constraint of having less than 0.1 million tonnes of gaseous CO₂ in Zones J and K outside the dome structures, 121 and 24 million tonnes of CO₂ can be stored in the Forties and Nelson dome structures, respectively. This was achieved by injecting 8 million tonnes of CO₂ per year into the two structures for 30 years. According to the simulation results, 80 million tonnes of CO₂ from the total 240 million tonnes is also expected to migrate in gas phase outside the regions below the Charlie Shale (which we assume it bears less risk of leakage to the surface in comparison with the region above field-wide Charlie Shale).

The calculated total capacity of 145 MT CO₂ corresponds to a total reservoir gas volume of 225 million rm³ combined from both structures extracted from the simulator outputs\(^1\). Considering that the original pore volume of the whole domain before application of PVM is 8,552 million rm³, the storage efficiency is 0.026 or 2.6%. This value agrees with the range of regional-scale storage efficiency values calculated to be 2% by Obi and Blunt, (2006), 2.3% by (Smith et al. 2011) and 3.5% by Goater et al. (2013) for UK Forties formation, and assumed to be 2% for Dutch CO₂ storage candidate sites by Wildenborg et al., (1998), Damen et al., (2009), and Ramirez et al. (2010) and in the range of 0.2% - 2% by SCCS (2009) for the UK North Sea formations. We conclude that in our study a combination of detailed geological data assimilation, dome stratigraphical volume calculation (using the zones’ horizons and water-oil contact), and constraining the simulations by pressure and migration, have resulted in reliable storage capacity estimates for Forties and Nelson dome structures.

Future work includes:

- Considering a three phase CO₂-oil-brine system that accounts for oil remaining unproduced from the hydrocarbon production stage. In this way, the feasibility and potentials of CO₂-EOR (Enhanced Oil Recovery) can be assessed and consequently a more realistic situation in which the reservoirs are not assumed fully depleted can be considered.

- Accounting for the uncertainties in the petrophysical properties of the geological model.

\(^{1}\) This value can also be obtained by assuming a reservoir condition density of CO₂=600 kg.m\(^{-3}\), 145 million tonnes / 600 600 kg.m\(^{-3}\) = 241 million m\(^3\)
Acknowledgements

The authors appreciate the constructive comments of the anonymous reviewers of the paper. This research was carried out as part of the UK Research Councils’ Energy Programme funded consortium projects “Multiscale Whole Systems Modelling and Analysis for CO2 Capture, Transport and Storage”, Grant Reference: NE/H01392X/1 and “CO2 Injection and Storage - Short and Long-term Behaviour at Different Spatial Scales”, Grant Reference: EP/K035967/1. The computational resources were provided by the University of Manchester EPS funding. The authors would like to thank this institution.

Appendix – Area-Type definition for Forties Sandstone Member

The Forties Sandstone Member comprises submarine fan sandstones made up of a huge number of interconnected amalgamated channels and interchannel areas that change laterally and vertically creating a very complex ‘plumbing system’. The ‘Forties Fan’ can be regarded as an open system - though it is probably closed on its south-eastern, south western and north-eastern sides. It is probably open to the northwest.

The Forties fan is 300 km by 100 km at its widest spread and trends NW-SE and, in general, to the SE the reservoirs will become deeper, and thinner, will have lower mean NTG and lower, but still fair to good, porosities, will have poorer permeabilities (by factor of 10 less). In addition, to the SE, any structural closures present are more likely to be formed by salt movement.

Numerous hydrocarbon fields are located in different parts of the Forties fan:

- **Proximal**: mostly channelised turbidite reservoirs such as Forties and Nelson fields, high NTG (65%), porosity 23-26%, permeabilities hundreds of mD
- **Distal**: turbidite reservoirs less frequently channelised such as Pierce and Starling fields, more typically overlapping lobes and/or sheets, lower NTG (50%), porosity 16-23%, permeabilities tens of mD

There is a clear and progressive downdip thinning: 259 m at the Forties Field (proximal area) and 137 m at the Pierce Field (distal area). Three potential Area Types have been identified based primarily on palaeogeography (i.e., location on fan complex) (Figure 1 in the manuscript).

Area Type 1

The 3D model has been built from an area that includes the Forties and Nelson fields located in the central part of the Forties fan. The reservoir in this 3D model exhibits lateral and vertical variation in petrophysical parameters, reflecting the evolution of the Forties submarine fan in a relatively proximal location. The model has been attributed using data from the Forties and Nelson oil fields and information from wells drilled in the area. Each zone in the model is divided into two facies associations namely ‘channel’ and ‘interchannel’ areas:

Amalgamated channels

There are four elements to the amalgamated channels – channel sands, low permeability basal lags, high permeability basal lags and intra channel doggers as shown in Figure A1.
Interchannel areas

The ‘Interchannel’ areas and associated channel margins contain muddy debris flows, slump deposits, thin-bedded turbidites and mudstones. Mudstones form vertical permeability barriers to the sandstones present.

![Diagram of interchannel areas]

**Figure A1.** Illustration of different facies in Area Type 1. Cartoon modified after Mayall et al. (2006)

Table 2 in manuscript reports the facies-dependent attributes of the Area Type 1 geological model, and Babaei et al. (2016, Tables 1 and 2) summarises the objects’ shapes and geometrical parameters used for representing the different facies in Area Type 1.

**Area Type 2**

Area Type 2 reservoir attribution is based on data from Montrose, Arbroath, Arkwright and South Everest fields and core measurements from two wells. The following table reports the data for Area Type 2.

**Table A1 – Data for Area Type 2**

<table>
<thead>
<tr>
<th>Data source</th>
<th>Depth to top</th>
<th>Thickness</th>
<th>Porosity</th>
<th>Permeability</th>
<th>NTG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arbroath &amp; Montrose fields (Crawford et al., 1991; Hogg 2003)</td>
<td>2447.5 &amp; 2451 m</td>
<td>100.6(79.2 – 134.1)</td>
<td>24(3-30)</td>
<td>80(1-2000) Commonly 70 to 90 mD</td>
<td>0.5(0.3 – 0.8)</td>
</tr>
<tr>
<td>Arkwright (Kantorowicz 1999)</td>
<td>2578 m</td>
<td>153 m</td>
<td>19.25(15.9 – 21.0)</td>
<td>38.4(24-78)</td>
<td>0.78(0.61 – 0.91)</td>
</tr>
<tr>
<td>South Everest (Thompson &amp; Butcher 1991)</td>
<td>2591</td>
<td>21</td>
<td>46</td>
<td></td>
<td>0.67</td>
</tr>
</tbody>
</table>
Area Type 3

Structures and closures are compact, generally circular, and smaller. The structures are often due to underlying salt movement. Radial faults may act as baffles but unlikely to compartmentalise reservoirs (Birch and Haynes, 2003; Kantorowicz et al., 1999). The following table reports the data for Area Type 3.

Table A2 – Data for Area Type 3

<table>
<thead>
<tr>
<th>Data source</th>
<th>Depth to top</th>
<th>Thickness</th>
<th>Porosity</th>
<th>Permeability</th>
<th>NTG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pierce</td>
<td>145.8 m</td>
<td>18(16-20)</td>
<td>19(1-40)</td>
<td>0.47(0.01-0.77)</td>
<td></td>
</tr>
<tr>
<td>Mungo</td>
<td>100 – 400 m</td>
<td>19 -24</td>
<td>10-50</td>
<td>0.43-0.63 to 0.25</td>
<td></td>
</tr>
<tr>
<td>Machar</td>
<td>21 average</td>
<td>5-50</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Everest</td>
<td>2560</td>
<td>19</td>
<td>16</td>
<td>0.55</td>
<td></td>
</tr>
<tr>
<td>(Thompson &amp; Butcher</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1991)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 23/22a-3</td>
<td>17(2.2-22.5)</td>
<td>11.5(0.01-70)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well 29/03a-7</td>
<td>141.7 m</td>
<td>22(2.3-27.1)</td>
<td>297(0.004-675)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SUMMARY</td>
<td></td>
<td>20(16-27)</td>
<td>20(1-600)</td>
<td>0.51(0.01-0.77)</td>
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</tr>
</tbody>
</table>
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