Integration of reservoir simulation, history matching, and 4D seismic for CO₂-EOR and sequestration at Cranfield, Mississippi, USA [☆]

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Abstract

In this paper, we compare 4D seismic interpretations of CO₂ plume evolution with fluid-flow numerical simulation results for Cranfield, Mississippi. Historic pressure trends, oil and gas production rates, and current CO₂-EOR production data from the field were history matched, and a tuned model was used for predictive simulations.

For CO₂-EOR operations, numerical simulation results of the CO₂ plume distribution and CO₂ first arrival (breakthrough) times in production wells were compared to the available field data. Three interpretations of 4D seismic data show discrepancies on the edges of the seismic survey, and along the sealing fault, where numerical simulations show high CO₂ saturations. In areas between these two limits, the match between simulation and 4D seismic interpretation improves. In addition, for most of the production wells, comparison of the breakthrough time of CO₂ showed a reasonable match.

The tuned model was then used to predict reservoir response and storage capacity in different field development scenarios under CO₂ injection. We compared hypothetical scenarios where the operator transitions from CO₂-EOR to CO₂ injection without oil production (CO₂-EORT) when oil production is

[☆]Abbreviations used in this paper: EOR (enhanced oil recovery), EORT (enhanced oil recovery transition), VRR (voidage replacement ratio), CCS (carbon dioxide capture and storage).

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not economical anymore, to a scenario of continuing with CO₂-EOR. Our results show that CO₂-EOR can store more CO₂ and operations will last longer, whereas if switched to CO₂-EORT, the field must be abandoned earlier because of spillover of the CO₂ plume. However, the amount of CO₂ stored per year is larger for CO₂-EORT as compared to CO₂-EOR.

Keywords: CO₂ enhanced oil recovery, 4D seismic, Numerical simulation, Carbon dioxide sequestration, Monitoring

1. Introduction

Geologic storage of CO₂, whether in a dedicated saline storage site or by use of CO₂ for enhanced oil recovery (EOR), is done to provide long-term isolation of the CO₂ from the atmosphere. To provide confidence that this goal is achieved, a program of (1) characterizing the subsurface, (2) modeling the expected outcome of the injection, and (3) validating the model through targeted monitoring observations is undertaken in such projects. A validated model can be used to assess the value of one engineering decision or another to meet the storage goal.

In this study, an EOR project at Cranfield, Mississippi was used to demonstrate this process. Geologic and fluid characterization data were used to develop a finite-difference numerical model to history match and to simulate current and future field operations. The static model used here covers the entire Cranfield reservoir. The model was initially history matched to historical oil and gas production data, and further matched to data collected during the more recent CO₂-EOR flood development of the field. The model was then used to conduct a few experiments for hypothetical scenarios to forecast long-term CO₂ storage capacities.

In addition, an interpretation of fluid distribution based on analysis of time-lapse 3D seismic data (also known as 4D seismic data) was compared to the model results. A similar comparative study has been done in the well-known Sleipner CO₂ injection project. In an effort to better understand the reservoir

response and effective drive mechanisms in Sleipner, Cavanagh et al. [1] and Cavanagh and Haszeldine [2] performed simulation studies on the storage site and used 4D seismic data to calibrate their numerical model and analyze the major physical processes controlling the plume movement in formation. Two contrasting simulation approaches were employed in that research: a capillary-based flow simulator, and a Darcy-flow-based simulator (black oil). Cavanagh et al. [1] concluded that for the Sleipner CO₂ storage project, a viscosity-pressure gradient mechanism (Darcy-flow dominated) was not capable of addressing the near-equilibrium flow mechanism observed in the reservoir. On the other hand, a pressure-compensated approximation of the near-equilibrium condition (achieved by extending the simulation time beyond the injection period and leaving the reservoir to reach an equilibrium state) provided an excellent match to the spatial distribution of CO₂. This strongly favors a gravity-segregated/capillary-dominated flow mechanism for CO₂ in the Sleipner site.

Many tools and techniques at the pilot- and field-scale project have been deployed and tested in the last decade to demonstrate their strengths and weaknesses for CCS monitoring [3, 4, 5, 6, 7, 8]. Using seismic surveys as a monitoring method has the advantage of covering a large area that can provide information about CO₂ saturation/distribution at locations where no monitoring wells exist. High-resolution seismic methods have shown great potential for incorporation into CO₂ injection (flood) management, highlighting the necessity of frequently updated reservoir simulation models [9, 10]. Although there are methods to alleviate some of the problems associated with seismic interpretations [11], an understanding of seismic data and the handling of unwanted noise and consequent misinterpretations is not always straightforward. Factors such as reservoir geology, pressure, depth, fluid compressibility and composition, seismic resolution, and repeatability play an important role in determining the reliability of 4D seismic methods and the assessment of the corresponding technical risk [12]. Arts et al. [13] and Eiken et al. [14] reported successful CO₂ monitoring projects in three different CO₂ storage sites (Sleipner, In Salah, and Snøhvit) where 4D seismic data provided a powerful tool for mapping supercritical CO₂

saturations.

55 4D seismic data were collected at the Cranfield CO₂-EOR site to characterize the plume development during CO₂ injection [15, 16, 17, 18]. Simulation studies on this field [19, 20, 21, 22, 23, 24] show the importance for CO₂-EOR performance of an appropriate permeability (facies) model, fluid distribution, boundary conditions in modeling field data, and injection/production strategies. 60 In this paper, we compare 4D seismic interpretations of CO₂ plume distribution [15, 17, 18] with fluid-flow numerical simulation results for Cranfield, Mississippi. First, we history match the historic pressure trends and oil and gas production rates. Then, the history-matched model is tuned to match current CO₂-EOR production data from the field. Finally, we use the tuned model for predictive 65 simulations. We history match the model against the injection and production data only, then compare the results of numerical simulations for CO₂ plume distribution with 4D seismic interpretations. The numerical model is then used to predict reservoir response and storage capacity in different field-development scenarios, specifically, in which an operator transitions to CO₂ injection without oil production (CO₂-EORT) when oil production is not economical anymore, 70 versus a scenario in which an operator continues with CO₂-EOR. Details about these scenarios are provided in the following sections.

2. Overview of Cranfield Development

The Cranfield reservoir is located in Adams and Franklin counties, Mississippi, east of the town of Natchez. The reservoir was first discovered in 1943 75 [25]. The reservoir has a near-circular anticline structure over a deep salt structure. The first producing oil well in Cranfield was drilled in 1944. The original productive area of the reservoir was estimated to be 31.3 km² (42 vol% of reservoir was oil) with a producing depth range of 3,060 to 3,193 m. Downdip, 80 an active aquifer provided a constant pressure boundary. The initial reservoir temperature was reported to be 125°C with an initial reservoir pressure of 32.4 MPa at 3,040 m. A sealing fault divides the productive zone into two reser-

voirs (white NW-SE polygon in Figure 1). The productive formation (known as lower Tuscaloosa ‘D’ and ‘E’ sands) is a conglomeritic sandstone with chlorite and quartz cements. Discontinuous shaly zones partly compartmentalize the reservoir. Ninety-three wells drilled in the reservoir allowed an ultimate liquid hydrocarbon recovery of 37 million STB. A pressure maintenance plan used Tuscaloosa-produced gas along with gas from other zones to reinject the reservoir gas cap. In 1959, the operator blew down the gas cap and in 1966, the field was abandoned. Over the next several decades, a strong water drive restored pressure to near-initial levels.

In 2008, CO₂-EOR was initiated by Denbury Onshore, LLC to sweep the bypassed residual oil. Between 2008 and 2015, more than half of the oil ring (Figure 1) was developed using a semi five-spot injection pattern with continuous CO₂ injection. Initial patterns started in the northern part of the field and continued clockwise around the oil ring. By January 2015, more than 5 million metric tonnes of CO₂ were stored in the formation. To monitor the CO₂ injection progress, two seismic surveys were conducted, one in 2007, before the injection process was begun (this survey covered the entire field), and the second in 2010 after a considerable amount of CO₂ had been injected into the reservoir (only the area within the dashed black line in Figure 1 was covered in this repeat survey).

3. Numerical Model Description

The reservoir model used in this study was calibrated using historic data as well as CO₂-EOR data from 2008 onward. Cranfield historic data cover monthly oil and gas production, water cut, and average reservoir pressure. More recent CO₂-EOR data include gas, water and oil production and CO₂ injection rates [19, 22].

This study is a field-wide extension of the work of Hosseini et al. [22]. They assessed only part of the reservoir, focusing on the response of only two wells in the detailed area study (DAS). Well logs were used to generate multiple possible

realizations that honor the well-testing data; these realizations assumed to be representatives of the reservoir geology. Analysis was then extended to the entire northeastern section of reservoir (with nine wells) separated by the sealing fault. Then boundary conditions and connectivities were evaluated and tuned by
115 investigating pressure changes during the CO₂ injection period. Miscellaneous reservoir data such as bottom-hole and well-head pressure, CO₂ breakthrough time, and U-tube gaseous-phase compositional samples were used afterwards to further narrow down the realizations that better represent the reservoir and also
120 honor reservoir-related observations. Hosseini et al. [22] used a purely mechanistic approach to recognize eight different facies (flow zones) in the reservoir based on combined permeability and porosity sets. Each flow zone is given a porosity and permeability value that is constant for the entire zone. These flow zones, which make the entire reservoir model, are categorized under two main
125 groups of low permeability (shale) and high permeability (sand). Although the flow zones in these two main categories each have their own permeability and porosity, members of each group (shale and sand) share the same relative permeability curves (Figure 2).

In the present study, the CMG-IMEX black oil simulator (Computer Modeling Group, Calgary, Canada) was used for simulation of historic and CO₂-EOR.
130 The simulator was set up to model four fluid phases including water, oil, gas, and solvent (CO₂). CO₂ behavior is modeled as solvent using the pseudo-miscibility approach [26]. Pseudo-miscible models are capable of simulating first-contact and multiple-contact miscible processes. This approach is capable of modeling
135 essential features of miscible flooding using a fairly coarse numerical grid, eliminating the necessity of using the fine structure of unstable miscible flow. Solvent and oil interaction in this model is handled by introducing a mixing parameter (ω), which determines the amount of mixing between the fluids in the reservoir. For a negligible dispersion rate, $\omega = 0$; for complete mixing of solvent and oil,
140 $\omega = 1$ (for more information, see the CMG-IMEX Users Guide). A Cartesian model with a $124 \times 49 \times 20$ (x $\times$ y $\times$ z) grid is used to model a total reservoir area of 7.5 km $\times$ 9.1 km with a total reservoir thickness of 24.4 m. Total number

of grid blocks is 369,520 where all grid blocks have a uniform dimension of $61 \times 61 \times 1.2$ m. The simulation model is isothermal at 125°C and neglects the possible reactions between minerals and fluids (injected and in situ), as they are reported to be minimal [27]. Permeability and porosity distributions are from Hosseini et al. [22]. We have also used the water-oil and oil-gas relative permeability data from Hosseini et al. [22] and neglected the capillary pressure effects.

Figure 3 shows the permeability and porosity maps used in this study. The ratio of vertical to horizontal permeability is considered to be 0.1. High-permeability channels in the lower Tuscaloosa Formation at Cranfield has been mapped and confirmed by various sources of data [28, 29]. However, the geometry of high-permeability channels throughout the field used in the model (Figure 3) are based on probabilistic extrapolation of the available data [22]. The role of such heterogeneities in increasing the CO_2 spillover risk will be discussed later.

In the numerical model, we consider an active aquifer with a porosity of 0.07 and permeability of 70 md to surround the reservoir from the outer boundaries. CarterTracy approximation is used to calculate water influx from the aquifer (see CMG-IMEX Users Guide for more information and assumptions). Water is allowed to flow from the aquifer into the reservoir and from the reservoir into the aquifer depending on the pressure gradient. Table 1 summarizes other reservoir properties used in the numerical model.

4. History Matching of Cranfield Production

Before starting the CO_2 flood simulation, we calibrated the model by history matching the average field-wide reservoir pressure, monthly oil and gas production rates, and water cut data from 1943 to 1966. For history matching, oil production rates were used as constraints to match the average reservoir pressure, water, and gas production rates. The history-matched model was then used to estimate reservoir conditions in 2008 (before the start of CO_2 injection). Knowledge of fluid saturation distribution prior to the seismic sur-

veys was of specific interest for us because high gas saturations in the reservoir could have affected the quality and reliability of the seismic interpretations and CO₂-EOR operations. Figure 4 shows the historic field data and simulation match for Cranfield. There are slight differences for oil production data (even though the oil production rate is used as a hard constraint) because to plot the field data we digitized Weaver and Anderson [25] plots, while for numerical simulations we used monthly production data from the Mississippi Oil and Gas Board, which looks slightly different. The blowdown in 1959, when operator decided to produce the gas cap before abandoning the field, can be seen in Figure 4b. Simulation models produce more gas in the blowdown process (and a correspondingly sharper decline in reservoir pressure as shown in Figure 4c) because maintaining the historical oil production rate is difficult when the reservoir is almost at residual oil saturation; to compensate, the simulator drops the bottom-hole pressure excessively low (below the oil bubble point), creating a high gas production rate.

To establish initial reservoir conditions at the beginning of CO₂-EOR operations in 2008, we extended the simulation by shutting in all the wells and allowing the reservoir and aquifer to interact and equilibrate. Figure 5 shows the final oil, gas, and water saturation distributions in the reservoir at the end of the reservoir development plan (1966) and the beginning of the CO₂ injection operations (2008). Because of the low pressure of the reservoir in the late 1950's and early 1960's, the oil zone is invaded by the surrounding aquifer, yielding large water cut values. Between 1966 and 2008, the pressure of the abandoned reservoir built up as water moved into the reservoir to restore the original reservoir pressure (Figure 6). In 2008, most of the oil zone and gas cap had been invaded by water to lower the hydrocarbon saturation to residual levels (Figure 5).

5. CO₂-EOR

200 In this section, we model a CO₂-EOR operation starting in 2008. Simulation results from history matching of historical production data are used for initialization of the CO₂-EOR model. This is different from initializing the entire reservoir at residual saturation, allowing us to study the performance of CO₂-EOR operations while considering historical production data. For history
205 matching of CO₂-EOR operations, we modify only those parameters that will not affect our previously history-matched models, including minimum miscibility pressure for CO₂ and density and viscosity of CO₂.

5.1. History matching of CO₂-EOR

Data gathered over 2.25 years of CO₂-EOR were used to calibrate the numerical model for a more reliable forecast of reservoir response to CO₂ injection.
210 Measured CO₂ injection rates for each injection well were set as a constraint; in production wells, we used a constant bottom-hole pressure constraint. Production wells in this field are operated without an artificial lift. Our goal was to history match oil, water, and gas production during the period from June
215 2008 to August 2010. Cumulative production was calculated based on the fluid produced after June 2008. In this section, static reservoir properties (validated through the history match) remained intact, and history matching was performed using production well constraints, injected fluid properties, and ω . To reduce the run time, we performed some preliminary history matching using
220 only 1 year of production data. Cases without an acceptable match for this shorter production period were ruled out (results not shown). After that, a complete history match for the entire 2.25-year injection/production period was performed on the acceptable cases.

Figure 7 shows cumulative oil, water, and gas production for different cases.
225 Solid red lines show the best match between the field data and the simulation results, while dashed gray lines show the remaining cases. Our best simulation model reasonably matched the field data. This increased our confidence to

advance to using this model to compare the output saturations with interpreted 4D seismic and observed CO₂ breakthrough times, as well as to run predictive scenarios. Note that 4D seismic and CO₂ breakthrough times were not used for history matching but were used for quality control over the outputs of the history-matched model.

Figure 8 compares the actual field CO₂ breakthrough times with those of the history-matched model for fourteen production wells. Results show that the history-matched model was able to predict the breakthrough times fairly well. The model underestimated some breakthrough times and overestimated others but showed no specific bias, which was a reasonable outcome given that the geologic model was probabilistic and the production history match was based on field-wide cumulative rates.

5.2. 4D seismic interpretation versus numerical simulation

Two seismic surveys were shot at the northeastern part of Cranfield, one before and one after CO₂ injection started. The first survey was taken in 2007 (baseline) and the repeat survey was taken in 2010 over the entire active northeastern part of the reservoir, by which time approximately 2.2 million metric tonnes of CO₂ had been injected. The repeated region covers an area of approximately 6 km × 6 km (area within dashed line in Figure 1). Sensitivity of the seismic response to the injected CO₂ saturation in Cranfield was analyzed using a number of different methods and assumptions [15, 17, 18]. 4D seismic results were compared to saturation distribution maps obtained from numerical simulations (Figure 9).

Zhang et al. [17] obtained elastic properties of the reservoir by applying a pursuit pre-stack inversion on a time-lapse amplitude versus angle data set. Figure 9a shows the acoustic impedance difference of pre-injection (2007) and post-injection (2010) surveys (reproduced from Zhang et al. [17]). The inversion results at the boundaries were not reliable because of limited fold and other boundary effects. Areas with a larger impedance difference were most likely to be influenced by injected CO₂ (more pronounced changes in elastic properties

due to CO₂ invasion and alteration of reservoir fluid properties). Figure 9a shows areas of CO₂ plumes in which the numerical model reasonably matched the 4D seismic interpretation. Setting aside mismatches near the edges of the study area, the most significant difference between the seismic measurement and the model was in the center of the study area along the sealing fault, where numerical simulations predicting high CO₂ saturation but no change in seismic impedance were observed.

In another independent effort to interpret the CO₂ plume shape and location in Cranfield, Carter [18] linked elastic properties of the media to the variations of CO₂ saturation, lithology, and cement content using rock-physics models and estimated a CO₂ saturation distribution map at the time of the 2010 survey (Figure 9b). The CO₂ saturation distribution map estimated by Carter [18] is similar to that of Zhang et al. [17] in that it also failed to show any sign of a CO₂-invaded zone in the mid-field area along the fault but provided a few patches of high CO₂ saturation with partial matches to the simulation model. Similar conclusions of limited matches but missing areas can be drawn when looking at the seismic amplitude difference map presented by Ditzko et al. [15] (Figure 9c). From these various seismic interpretations it seems adding the rock-physics model or pursuit pre-stack inversion does not really improve the results compared to the simple amplitude difference.

In general, it seems that the discrepancy between the numerical simulation outputs and these three seismic interpretations is large. The mismatch between the modeled saturation and the seismic change near or outside the edges of the seismic data can be interpreted as a consequence of seismic data from too small an area, so that robust interpretations of saturation cannot be made from these data. The matches in the plumes shown in both the modeled and the seismic interpretation can be understood several ways: the comparison among the seismic interpretations gives an estimate of an uncertainty based on the interpretation algorithm. An additional uncertainty based on data collection (signal strength, noise, repeatability, and so forth) can consider the interpretation of the seismic data in the areas distant from where any CO₂ was emplaced, for example south-

east of the center of the study area. No seismic interpretation shows a large
 290 signal in this area. However, small spots are shown on Figure 9a and Figure 9c.
 Ignoring these disconnected signals is part of the reasoning behind the interpretation of the simplified plumes (dashed lines). Some level of mismatch between the observed and modeled change can also be attributed to uncertainties; given that the permeability distribution in the model is probabilistic, we may conjecture that this may cause some differences in shape and orientation between the
 295 observed and modeled plumes. In addition, a low net-to-gross ratio in parts of the formations may hinder seismic interpretations. The last mismatch to be considered is the central area along the fault where the model shows a large amount of CO₂, but none of the seismic interpretations show a significant change. In the
 300 model, this central plume is well constrained by well-quantified CO₂ injection as well as production. A small percentage of residual gas can reduce or mask acoustic change caused by the injected CO₂, and this has been suggested in the seismic interpretations of the area as a reason for the failure to locate the CO₂ plume related to these injectors [30]. This area is relatively bright in the
 305 seismic data, suggesting that gas may be accumulated updip against the faults influencing the seismic properties. Models shown in Figure 5 interpret this area as outside the maximum gas cap in 1966 (or 2008), which is not matching the field observations based on Weaver and Anderson report [25] that shows gas cap has had a much bigger extension in 1966 on both sides of the fault. Presence of
 310 hydrocarbons along the sealing fault can potentially be one of the reasons that CO₂ plume in 4D seismic interpretations is masked. Further work is needed to investigate these inconsistencies.

6. Forecast Simulations

In this section we use the tuned simulation model to experiment with strategies that can be deployed in the future at Cranfield (or, more importantly, extrapolated to similar fields). In our first case, to assess the maturation of the field, we assume that the pattern of injection and production continues through

2018. We exclude any consideration of modification of the flood by operator management (according to development plans, CO₂ injection will continue until
320 2018 to cover the entire field). We then consider two hypothetical post-2018 simulation scenarios in which the model is an offtake for CO₂ (not relevant to Cranfield, which, as part of a pipeline network, is operated in response to market forces, with no obligation to offtake). One case continues the CO₂-EOR operation until the site is overfilled with CO₂; the other continues to accept
325 CO₂ until overfilled but stops oil production at a cutoff point we establish as marking a decisive decline in economic value. A long-term post-injection stabilization simulation case follows these runs to analyze CO₂ behavior over a long period of underground storage.

6.1. Continuing CO₂-EOR

330 In this case, we assumed that field development in Cranfield would continue by developing new patterns around the oil ring. CO₂ injection was started in 2008 and the field is projected to be fully developed by 2018 with injection/production wells covering the entire reservoir. Figure 10 shows time lapses of vertically averaged CO₂ saturation in the reservoir from 2010 to 2018. According to our results, over time, more CO₂ is injected into the reservoir and
335 its saturation increases. In 2018, when the field is fully developed, a total of 24.1 million metric tonnes of CO₂ is injected into the reservoir, of which 10.8 million metric tonnes is stored in the reservoir and the rest has been recycled. We assumed that new wells that would be drilled until 2018 would inject with
340 the same average rate as all the current injection wells. No operator interaction in balancing the flood was considered.

White arrows in Figure 11a indicate several places where the modeled CO₂ plume reaches the boundaries of the reservoir model. This would be considered undesirable while performing CO₂-EOR, as we would lose some CO₂, a valuable
345 commodity, to the water leg. In this case, the CO₂ migrating out of the structure decreases the reliability of the project in ensuring CO₂ storage. Figure 11b shows a cross section of the reservoir along the dashed line drawn in Figure

11a. Injected CO₂ finds the high-permeability channels and flows outward to the model boundaries. In this model, pressure sinks created by production wells
 350 are not strong enough to confine the plume to within the production patterns, and the heterogeneity of the reservoir strongly affects the plume movement. Looking at permeability distribution maps helps us to understand this behavior better (Figure 11c and Figure 11d). High-permeability channels in the reservoir (marked with white arrows) present a risk that CO₂ can move along fast paths
 355 outside the patterns and spill out of the structure. In the case of CO₂ injection with no production, heterogeneity might be even more important.

Water flow in or out of the reservoir can now be evaluated to further understand the direction of fluid movement and pressure gradients. Figure 12a shows the aquifer influx rate before and during CO₂-EOR. Water starts flowing
 360 out of the reservoir (negative aquifer influx) when CO₂ injection commences in 2008. The strong outward water flow shows that injection is not balanced by production, which raises the possibility of CO₂ spillover from the reservoir. In addition, analysis shows that at the beginning of the CO₂-EOR operations, the voidage replacement ratio (VRR) is well above one, indicating that the injected
 365 volume is greater than the produced volume. VRR is defined as the injected reservoir volume divided by the produced reservoir volume, as shown in Figure 12b. A VRR of one, achieved later as more production wells are added, indicates a net balance of injection and production fluids. Note that this model is a case study, not a prediction, as the operator has many possible choices in the
 370 operation of this field. In addition, other evaluations are needed to assess the interactions of fluid flow with gravity, as neither the structural model nor the fluid flow model is optimized at the edges of the model area.

6.2. CO₂-EOR versus CO₂-EORT

In this section, we analyze and compare CO₂-EOR and CO₂-EORT scenarios.
 375 In the CO₂-EOR scenario, we pose a simple case in which CO₂ injection and oil production will continue during the model period until large volumes of CO₂ start migrating out of the model area, which is defined as the project end.

We arbitrarily define ‘large’ migration as the case where average CO₂ saturation in one face of the reservoir boundary passes 5%. This simple definition lets us
380 compare different scenarios in a consistent way.

In the CO₂-EORT scenario, we pose a case in which, at some point in the reservoir’s life, oil production from the field is not economical anymore and the operator decides to use the field only for CO₂ storage. In real life, a cutoff value depends on many parameters such as oil price, operational costs, and others; for
385 this case, we assign an arbitrary cutoff value (150 m³/D of field oil production rate 950 bbl/D). When production declines to the cutoff value, all producing wells are shut in, but injection wells continue injecting CO₂ at a constant rate, creating a transition to a storage-only scenario. The injection rate of the wells is fixed to the net CO₂ storage rate (difference of injection and production) at the
390 time of transition. In the CO₂-EORT scenario, we use the same abandonment criteria as in the CO₂-EOR case; that is, average CO₂ saturation in one face of the reservoir boundary passes 5%.

Figure 13 shows the modeled CO₂ and oil rates for the CO₂-EOR scenario. In this scenario, CO₂ injection continues until 2070, when large volumes of CO₂
395 start leaving the reservoir at the boundaries. For the CO₂-EORT scenario, the cutoff value of 150 m³/D, at which point the production wells are shut in and switched to injection-only mode, starts around 2045.

Figure 14 shows CO₂ saturation distribution maps for both CO₂-EOR and CO₂-EORT scenarios at the ends of their operations. As shown, in the CO₂-
400 EOR scenario, CO₂ injection should continue until 2070 before bulk CO₂ leakage starts at the northern boundaries of the reservoir. In this scenario, production wells act as sinks, drawing the CO₂ plume toward the center of the reservoir. However, the injection period is too long for some CO₂ to eventually reach the boundaries. In this scenario, a large part of the injected CO₂ is recycled and
405 reinjected into the reservoir.

In the CO₂-EORT scenario, the oil production rate drops below 150 m³/D around 2045 (oil production stops after this point). Heavy CO₂ migration outside the model area occurs only 9 years later, while large areas of the reservoir

are poorly swept by CO₂. Within these 9 years, the amount of CO₂ stored per
year is larger than in the CO₂-EOR scenario because the recycling process is
410 stopped. However, the total cumulative volume of stored CO₂ in the project
is lower, because the process has to stop earlier and less of the pore volume
is used. A detailed economic analysis is required to decide which approach is
better.

415 Figure 15a shows the average reservoir pressure and amount of stored CO₂
over time for both scenarios. For CO₂-EORT, the reservoir pressure increases
rapidly immediately after the production wells are shut in. This relatively higher
reservoir pressure is the main force that pushes the injected CO₂ through the
channels and toward the boundaries, shortening the life of the storage operation
420 to only 9 years.

On the other hand, in the CO₂-EOR scenario, the average reservoir pres-
sure does not increase. Because CO₂ moves from high-pressure injection wells
into low-pressure production regions, the simultaneous injection and produc-
tion delays CO₂ migration out of the model area. As shown in Figure 15b,
425 the CO₂-EOR scenario increases the CO₂ storage capacity by 9% over the CO₂-
EORT scenario (CO₂ storage capacity increases from 22.2 to 24.1 million metric
tonnes). However, in the first 9 years, the average injection rate in CO₂-EORT
is higher than in CO₂-EOR (0.174 versus 0.160 million tonnes per year) because
of lack of recycling. For CO₂-EORT, we assume that the recycling stream is
430 closed, and only a make-up stream will continue at a constant rate. This means
that the total injection rate during CO₂-EORT is much lower than CO₂-EOR
operations. If the same total injection rate during the CO₂-EORT were kept,
the injection rate would be much higher than 0.174 million tonnes per year.

Based on the lessons we learnt from this study, it appears replacing the
435 continuous gas injection scenario with a water alternating gas case (WAG) can
help to achieve a better sweep and storage efficiency. Another field development
recommendation is to drill new wells in regions where simulation results predict
high CO₂ saturations but seismic interpretations show no traces of a highly
compressible fluid. Finding no CO₂ in those areas can guide the operation

440 to find the unswept regions of the formation using the current interpretations
for a better EOR performance. As previously commented, another point of
uncertainty, yet to be cleared up, is the presence of the gas cap. We are still
unclear on the extent of the gas cap in this field. Better characterization of the
gas cap in the field would be very helpful to strategize for field developments.

445 **7. Post-injection CO₂ plume movement**

Post-injection movement of the CO₂ plume is another factor in storage capacity assessment for CO₂ injection projects. The injection reservoir should be capable of not only accepting and storing CO₂ during the injection period, but also of providing acceptable support for the post-injection period by trapping
450 the injected CO₂ by different mechanisms such as structural, geochemical reaction, residual, and dissolution trapping. To evaluate reservoir response for the post-injection time, we extended our numerical simulation for the CO₂-EOR scenario. Here, we omitted the geochemical reactions. We shut in all the injection and production wells in 2070 (24.1 million tonnes of CO₂ is stored in the
455 formation at this time) and let fluids stabilize for next 100 years (until 2170). Figure 16 shows a time-lapse of CO₂ saturation in the reservoir over 100 years post-injection. Mainly because of gravitational forces and aquifer-supported stabilization of reservoir pressure, CO₂ moves up, towards the center of the anticline, with the plume's areal extension around the model boundaries shrinking.
460 Extended simulations reveal that CO₂ migrates back into the reservoir and up to the center of the formation where previously there was no or minimal CO₂. In addition, the amount of CO₂ increases in the top part of the reservoir but is also balanced out around the injection wells, where high saturations initially existed. This helps to reduce the free-phase, mobile CO₂ in the reservoir, which
465 reduces the risk of leakage. CO₂ saturation remains high on the northeast side of the sealing fault.

8. Conclusions

Numerical models can be used to evaluate and assess the storage performance of CO₂ injection for CO₂-EOR and storage. However, the validity of these numerical models can be checked against field observations. Validated models can then be used to forecast outcomes to different field development designs. In this study, we first calibrated a numerical simulation using data collected from the field. This included historical production and injection data from 1944 to 1966 and more recent CO₂-EOR data from 2008 to 2010.

We contrasted the results of this calibrated model to two other independent data sets from the field, namely breakthrough times of CO₂ in production wells and 4D seismic interpretations of CO₂ plumes in the reservoir.

A numerical simulation model of CO₂ breakthrough times in fourteen production wells matches field observations reasonably well. This supports the conclusion that our static and dynamic reservoir models work well and that the level of heterogeneity defined in the static reservoir model is adequate. Our comparison of CO₂ saturation distribution to interpreted 4D seismic data is not as successful, and there are clear discrepancies. Three interpretations of the 4D seismic data show discrepancies with each other and with the fluid flow model with regard to missing CO₂ plumes and inconsistent plume locations. These discrepancies can be attributed to several factors, including uninterpretable data on the edges of the seismic surveys, minimal gas saturation along the sealing fault, the probabilistic nature of the static model that directs the CO₂ plume distribution in the simulation model, and a low net-to-gross ratio in parts of the formations that would hinder seismic interpretations. Sources of uncertainty in 4D seismic data in Cranfield need further assessment.

We then used the tuned numerical model to forecast simulation scenarios for CO₂-EOR (EOR continues for the whole of the project) and CO₂-EORT (at some point during the EOR, production stops and only injection continues). Our results show that the cumulative amount of injected CO₂ is greater for the CO₂-EOR scenario and it can continue for a longer time, but it will come with

higher costs (production wells, recycling, and so forth), while with CO₂-EORT, the amount of CO₂ injected per year is higher (because there is no recycling); however, the field must be abandoned earlier because the CO₂ plume migrates
500 out of the model area faster. Our simulation results were utilized to recommend more efficient field development plans. High-permeability channels in Cranfield are the main conduits to move the fluids out of the zone, and even in the CO₂-EOR scenario, they could result in CO₂ migration towards the boundaries.

Extended numerical simulations show that the anticline structure of Cran-
505 field provides a reasonable structural trap for CO₂ emplaced during all scenarios and that most of the CO₂ pushed to the boundaries during the injection period will slowly move back upward during the post-injection period.

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Parameter	Value
Stock tank oil density	873 kg/m ³
Gas density at standard condition	0.942 kg/m ³
Water density	1,108 kg/m ³
Water compressibility above bubble point pressure	1.98E-09 Pa ⁻¹
Initial bubble point pressure	31.06 MPa
Original water oil contact depth	3,064 m
Original gas oil contact depth	3,008 m

Table 1: Fluids properties and contacts data used in numerical modeling of Cranfield.

Figure 1: Structural contour map of the Cranfield field with the historical well locations and original fluid contact levels. The map shows the sealing fault that divides the productive zone into two sections. Two seismic surveys were performed before and after CO₂ injection. First seismic survey covered the whole reservoir while the second survey was conducted in the region within the dashed black line.

(a) Water-oil relative permeability

(b) Oil-gas relative permeability

Figure 2: Relative permeability curves used in this study.

Figure 3: Porosity and permeability distribution maps used in the numerical simulations. Permeability range is 0.01-4400 md and porosity range is 0.0002-0.45. Location of the sealing fault is shown by null grids in black.

Figure 4: History matching of the historic production and pressure data (1943 to 1966).

Figure 5: Ternary saturation distribution map in the reservoir shows that in 1966, water had swept the oil ring (around 40% oil saturation remaining). The gas cap was invaded by the brine as well because of the gas cap blowdown. By 2008, restoring the reservoir pressure from 13 MPa to 32 MPa compressed the remaining gas cap, and some of the gas dissolved back into the remaining oil.

Figure 6: Average reservoir pressure was restored to its original value within approximately 20 years of the field's abandonment in 1966.

Figure 7: The model that best matched the oil, water, and gas production data was selected for predictive and comparative simulation.

Figure 8: Comparison of actual and simulated CO₂ breakthrough times in production wells shows that current model performance is acceptable and has no bias toward underestimating or overestimating breakthrough times.

Figure 9: Comparison of different seismic interpretations with simulation results. Black dashed polygons show the matches and red dotted polygons show the mismatch between the 4D seismic data and the simulation model.

Figure 10: Timelapse CO₂ distribution map during field development plan. The field is fully developed by 2018 and the injection process covers the entire reservoir area.

Figure 11: High-permeability channels direct the injected CO₂ toward the reservoir boundary.

(a) Aquifer water influx rate

(b) Voidage replacement ratio (VRR) for Cranfield CO_2 -EOR project

Figure 12: (a) Aquifer water influx rates from 2005 to 2018 show water moving out of the reservoir (into the surrounding aquifer) as a result of CO_2 injection and pressure build-up. (b) A higher VRR at the beginning of CO_2 -EOR operations matches higher water flow out of the reservoir, increasing the possibility of the CO_2 moving toward the reservoir boundaries.

Figure 13: CO₂ injection/production rate and oil production rate for the CO₂-EOR scenario.

Figure 14: CO₂ saturation distribution map for two different scenarios (simulation stops in 2070 for CO₂-EOR and in 2054 for CO₂-EORT, when large migration out of the model area occurs) shows CO₂-EOR can store more CO₂ and achieve better sweep efficiency, but it has to continue for longer period of time.

(a) Average reservoir pressure

(b) Cumulative amount of stored CO₂

Figure 15: Average reservoir pressure increases when we switch from CO₂-EOR to CO₂-EORT. Higher reservoir pressure increases the possibility of early CO₂ migration out of the model area.

Figure 16: Simulation results show that injected CO₂ will stay and equilibrate within the reservoir boundaries 100 years after abandoning the field.