Laboratory Tests and Modeling of Carbon Dioxide Injection in Chalk With Fracture/Matrix-Transport Mechanisms

M. Ghasemi and W. Astutik, Petrostreamz A/S; S. A. Alavian, PERA A/S; C. H. Whitson, PERA A/S and Norwegian University of Science and Technology; L. Sigalas and D. Olsen, Geological Survey of Denmark and Greenland; and V. S. Suicmez, Maersk Oil & Gas A/S

Summary

The main focus of this paper is to present experimental and simulation results that describe carbon dioxide (CO_2) injection in a chalk sample with fracture/matrix interaction at reservoir conditions. On the basis of the experiments, simulation models were built to mimic the main transport phenomena, including diffusion, which was found to be particularly important.

The first experiment consisted of a vertically oriented Sigerslev outcrop chalk core, where a single "fracture" was represented by a centralized hole along the core. Both matrix and fracture were initially saturated with a North Sea stock-tank oil (STO) at reservoir conditions. Once the initial conditions were established, CO_2 was injected from the top of the fracture and the oil was produced from the bottom.

Injected CO_2 diffused into the oil in the matrix and swelled the oil. Once the oil in the fracture was drained, the matrix fed the fracture with oil at decreasing rates. The first experiment lasted up to approximately 24 pore volumes injected (PV_{inj}). The second experiment is similar, but laboratory oil *n*- C_{10} was used instead of STO. Laboratory oil and CO_2 have very similar densities at the chosen reservoir conditions, which minimizes gravity-driven convective (Darcy) transport and maximizes the effect of diffusion.

Our modeling was conducted with a compositional reservoir simulator. We developed and used a tuned equation-of-state (EOS) model that accounts for proper estimation of the phase and volumetric properties for CO_2 mixtures in the STO and *n*- C_{10} systems. Automated history matching was used to fit the experimental data. A commercial reservoir simulator could reproduce laboratory results adequately.

Numerical simulations were conducted to match experimental oil-production data by tuning the oil- and gas-diffusion coefficients. Good agreement between the numerical model and the experimental data was obtained. For the $n-C_{10}$ system, we found that the results were not sensitive to vertical permeability, confirming displacement was dominated by diffusion rather than convective flux.

Verifying the accuracy of modeling the diffusion-dominated processes in a fractured chalk system with CO_2 at reservoir conditions has been accomplished. The lesson learned from the experimental and modeling work flow obtained from this study becomes an important step toward modeling an actual fractured chalk/reservoir-oil system undergoing CO_2 injection.

Introduction

During the early life of fractured reservoirs, most oil is primarily produced from the fractures and significant amounts of oil remain in the matrix. High capillary pressures associated with the matrix block, coupled with the extreme hydraulic contrast between the matrix and the fractures, may result in low recovery efficiencies in such reservoirs.

In recent years, there has been a growing interest in CO₂ injection as a promising technique to improve oil recovery in naturally fractured reservoirs. Because of the special characteristics of the CO₂/oil-phase behavior, CO₂ injection provides certain advantages for enhanced oil recovery (EOR) over other solvents. It results in lower minimum miscibility pressure compared with nitrogen or lean hydrocarbon gases. CO₂ swells the oil and increases the liquid volume, and therewith lowers the residual oil saturation. The liquid viscosity of the CO₂/oil mixture is decreased considerably when CO₂ dissolves in oil, which results in higher oil mobility in the reservoir. However, when the CO₂ amount in the oil increases over a certain limit, CO₂ vaporizes the lighter components from the oil and the oil viscosity will increase. CO₂ reaches supercritical state for most of the oil reservoirs (T_R >46°C and p_R >73 bar), which results in oil-like density that reduces the override effect (Simon et al. 1978; Alavian and Whitson 2010; Moortgat et al. 2013).

Various experimental and numerical studies have been performed to investigate the effect of diffusion in naturally fractured reservoirs (Coats 1989; da Silva and Belery 1989; Morel et al. 1990; Le Romancer et al. 1994; Grigg 2000; Darvish et al. 2006; Hoteit and Firoozabadi 2009; Alavian and Whitson 2010). Coats (1989) included the matrix/fracture-diffusion term in the matrix/fracture-transfer function to model diffusion for dual-porosity numerical models. Results indicated a strong diffusion effect on the calculated gas/oil ratio from a volatile-oil reservoir when injected gas (e.g., N₂) differs significantly from the in-situ reservoir gas. The same conclusion was made by da Silva and Belery (1989).

Several studies were performed on North Sea chalk reservoirs to investigate the effect of diffusive-gas injection into a fractured chalk. Morel et al. (1990) conducted an experimental study to examine the efficiency of N_2 and C_1 injection into an outcrop chalk core saturated with a synthetic binary-oil mixture of methane and pentane, concluding that the recovery process was not a pure-diffusion process. A similar experimental setup was used by Le Romancer et al. (1994) to investigate the effect of molecular diffusion in a matrix block saturated with light binary oil, and then subjected to CO_2 , C_1 , and N_2 injection. This experiment was conducted at different initial water saturation. It was concluded that the fracture/matrix-transfer function was controlled by several physical mechanisms, including molecular diffusion. Hoteit and Firoozabadi (2009) modeled physical diffusion for gas injection in fractured oil reservoirs and gas recycling in gas/condensate reservoirs. They incorporated multicomponent diffusion coefficients to account for the diffusive flux in their numerical model. The gas/oil capillary pressure in the matrix block was neglected in their study. The results showed a significant effect of diffusion in the recovery performance when pressure is lower than minimum miscibility pressure. They also concluded that the

Copyright © 2017 Society of Petroleum Engineers

This paper (SPE 180102) was accepted for presentation at the SPE Europec featured at the 78th EAGE Conference and Exhibition, Vienna, Austria, 30 May–2 June 2016, and revised for publication. Original manuscript received for review 22 February 2016. Revised manuscript received for review 17 April 2017. Paper peer approved 10 May 2017.

diffusion process significantly affects the condensate recovery in a fractured condensate reservoir. Darvish (2007) performed a tertiary CO_2 -injection experiment into fractured chalk core, saturated with live oil. Alavian and Whitson (2010) successfully modeled the Darvish (2007) experiment with a numerical compositional model. Their results indicated that the recovery process was affected by gravity drainage, as well as the mass-transfer mechanism by molecular diffusion, vaporization, and condensation.

Unfortunately, only a few comprehensive laboratory data sets are available at reservoir conditions, where the core is saturated with STO or live oil. This becomes the main motivation of this study; which is to provide comprehensive laboratory, pressure/volume/ temperature (PVT), and modeling data on CO_2 injection in a fractured chalk core at reservoir conditions. These data, along with the lessons learned from this study, might be beneficial for future CO_2 -injection research and field application.

To achieve a proper insight into the fundamental transport mechanisms of CO_2 injection in naturally fractured reservoirs, we performed extensive experimental and simulation work of CO_2 injection in plug samples of Maastrichian Sigerslev outcrop chalk (Tor Formation). The experiments were conducted at 258.6 bara (3,750 psia) and 110°C, which is representative for a North Sea chalk reservoir. In addition, we developed a Peng-Robinson EOS (Robinson et al. 1979) derived from a comprehensive fluid study of the CO_2 /oil system. The tuned EOS model accounts for proper estimation of the phase and volumetric properties for CO_2 /oil mixtures.

We successfully isolated the diffusion-driven mechanism by conducting an experiment with a CO_2 /laboratory-oil binary mixture. We were able to match the experimental results by use of a diagonal matrix of diffusion coefficients where each element in the diagonal matrix represents the average diffusion coefficients for a specific constituent in the mixture. This work also addresses the importance of compositional dependency of the diffusion coefficients, which is neglected by some compositional simulators. It is shown that when PV_{inj} is high enough (PV_{inj} >10), the numerical models with the assumption of constant-diffusion coefficients cannot properly capture the real physics of molecular diffusion. However, this may not be an important concern for field applications under CO_2 injection because the PV_{inj} never (rarely) exceeds 10.

This paper is arranged as follows. First, we briefly describe the prediction of the developed EOS model, which is used to calculate the fluid properties for STO/CO₂ mixtures. We then discuss the results of two CO₂-flooding experiments. We will also discuss the results of the numerical simulations, which verify the accuracy of modeling the diffusion-dominated process for CO₂ injection in the Sigerslev outcrop chalk with fracture/matrix interaction at reservoir conditions. Finally, we conclude with the fundamental findings of our work.

PVT Laboratory Data and EOS Modeling

North Sea chalk field fluid characterization and the EOS model were developed by use of the available PVT data. The measurements included compositional analysis, standard depletion-type experiments [constant composition expansion (CCE), difference liberation expansion (DLE), and separator tests)], vaporization study, and oil-swelling tests as a function of dissolved CO₂. The detailed description of the EOS fluid characterization used in this work can be found in our previous study (Ghasemi et al. 2016).

CO₂-Flooding Experiments

Two CO₂-flooding experiments were conducted at reservoir conditions with chalk samples from the Tor Formation of the Sigerslev Quarry, Denmark. In the first experiment, the core was saturated with STO (STO experiment), whereas in the second, the core was saturated with *n*-C₁₀ (laboratory-oil experiment). The experiment with STO consists of a vertically oriented chalk core, approximately 7.4 cm long, with 3.7-cm diameter. A single "fracture" was represented by a centralized hole with diameter of 0.6 cm along the core, resulting in a pore/fracture-volume ratio of 18. Both fracture and matrix were initially saturated with STO at the North Sea chalk field reservoir conditions.

The laboratory-oil experiment has a setup similar to that of the STO experiment, but laboratory oil, n-C₁₀, was used instead of STO. The pressure and temperature for this experiment were selected to ensure that n-C₁₀ and CO₂ have the same density at the experimental conditions to minimize the gravity-driven convective (Darcy) transport, and hence maximize the effect of diffusion.

In all experiments, the core samples did not contain any connate water to avoid overcomplicating the diffusion-coefficient measurements between the CO_2 and oil. Table 1 summarizes the physical properties used for the experiments.

	STO Experiment		Laboratory-Oil Experiment		
	Fracture	Matrix	Fracture	Matrix	
Initial system pressure (bara)	258.5	258.5	335.9	335.9	
Temperature (°C)	110	110	100	100	
Porosity (%)	100	46.89	100	47.1	
Permeability (md)	_	2.47	-	2.6	
Length (cm)	7.368	7.368	7.483	7.483	
Diameter (cm)	0.6	3.757*	0.6	3.754*	
PV (cm ³)	2.08	37.32	2.12	38.01	
Flow direction in core	Downward		Downward		
Initial fluid at start of experiment	STO		<i>n</i> -C ₁₀		
Dead volume** (cm ³)	7.88		7.88		
* Sample diameter includes both matrix and fracture					

** Total dead volume from coreholder outlet to separator

Table 1—The physical properties used in the STO experiment and laboratory-oil experiment.

Fig. 1 shows a schematic of the experimental setup. The samples were mounted within a rubber sleeve in a hydrostatic core holder with water in the annulus to provide confining pressure. Confining pressure was applied with a piston pump with logging of the piston volume. The annulus is separated from the core by a rubber layer that is impermeable to water, but slightly permeable to CO_2 . It should be noted that the samples were wrapped with a metal foil to create a closed-boundary condition—i.e., to avoid CO_2 diffusion from the matrix to the annulus water. The core holder, pressure vessels with injection fluids, and the densitometer were placed in the rig within

an oven with air circulation to ensure uniform and stable temperature distribution. The pressure was maintained by a high-pressure pump system. A three-phase acoustic separator, placed outside of the oven, receives and quantifies the produced fluids. The separator was operated at the ambient temperature, $22-26^{\circ}$ C, and a pressure between 3 and 6 bar gauge. The experiments were controlled by a computer that performs data acquisition, such as the PVT data. Both matrix and fracture of the core sample were initially saturated with STO or laboratory oil at reservoir conditions. Once the initial conditions were established, CO₂ was injected from the top of the fracture, and the oil was produced from the bottom. The cumulative gas injection, the oil and gas production, and the system pressure were measured during experiments. Table 1 provides the dead volume of the experiments—i.e., the fluid volume of tubes and fittings.



Fig. 1—Schematic of experimental setup for the STO and laboratory-oil experiments. The dashed line shows the limit of the oven; pressure regulators and valves are not shown.

It is worth of mentioning that the Sigerslev chalk is a weakly consolidated rock that requires a net confining pressure lower than 20 bar to stay in the elastic regime. Throughout the experiments, the net confining pressure remained at less than 20 bar. After each experiment, it was observed that the rock appeared unaltered. The axial hole was fully open, and no evidence of microfractures was found. **Fig. 2a** shows the outlet end of the core sample after the STO experiment. As shown by Fig. 2a, the chalk core still sits in the rubber sleeve and the axial hole is fully open throughout the sample.

Compositional Modeling of STO and Laboratory-Oil Experiments

In this section, we first provide the details of the constructed numerical model. Then, we discuss our methodology to match the experimental results. A sensitivity analysis was performed to evaluate the dominance of different mechanisms in the STO and laboratory-oil experiments.

Model Description. We modeled the experiments with a commercial compositional numerical simulator. The ECLIPSE 300 (Schlumberger 2012) with fully implicit solution method was used for all the simulations.

The numerical model, a 2D x–z radial grid, includes both matrix and fracture (central hole). Fig. 2b shows the 2D schematic of the numerical model with x–z specified areas for matrix and single fracture. We conserved the PV of both matrix and fracture to be similar with the experiments.

Grid sensitivity was performed to find the optimal gridding scheme to reduce numerical dispersion and increase the run time efficiency. **Table 2** provides the selected grid properties for both experiments, which were found to be sufficient to eliminate the numerical effects. The developed numerical model was started with 100% oil saturation at reservoir conditions. Linear relative permeabilities were used for modeling the experiments. In addition, the fracture in all models was assumed to have zero capillary pressures. Because the central hole represents the fracture, we assigned porosity equal to unity and a "large" permeability of approximately 4,000 md. The properties used in our simulations are provided in Table 2.

The matrix gas/oil capillary pressure (P_{cgo}) was measured on the Sigerslev outcrop chalk in a mercury/air system. The P_{cgo} was then scaled to the interfacial tension (IFT) of the model system. **Fig. 3** shows the P_{cgo} capillary pressure data after scaling to IFT of 1.5 mN/m. The model was started at constant temperature of 110°C and pressure of 258.5 bara for the STO experiment, and at 100°C and 335.9 bara for the laboratory-oil experiment. As shown in Table 2, in the laboratory-oil experiment, liquid density at the initial reservoir condition for CO₂ is 0.699 g/cm³ and for *n*-C₁₀ is 0.698 g/cm³. This similarity minimizes the gravity-driven convective (Darcy) transport during the experiment. The STO composition used to start the matrix/fracture in the STO model is provided in **Table 3**.

For the laboratory-oil experiment, a constant injection rate of $3 \text{ cm}^3/\text{h}$ was used. However, the leakage that occurred at 11 hours caused the injection rate to decrease. Because the rate of the leakage was unknown, we consider it one of the history-matching variables. In the STO experiment, the initial injection rate was $5.73 \text{ cm}^3/\text{h}$. This rate was further reduced to $1.5 \text{ cm}^3/\text{h}$ after 164 hours. Higher injection rate at the start of the experiments accelerates the oil production from the fracture at early time, facilitating the CO₂ loading into the fracture and hence starting the diffusion process into the matrix. The injected CO₂ diffuses into the oil in the matrix and swells

the oil. Once the oil in the fracture has drained, the matrix feeds the fracture with oil at a decreasing rate. The cumulative oil production during the CO_2 flooding was the main history-matching parameter in the STO test.



Fig. 2—(a) End outlet of the core sample after Experiment STO-1; note the fully open axial hole. (b) The numerical grid cells used in the 2D radial model. The centralized hole (dashed line) inside the core represents a "fracture."

	STO Experiment		Laboratory-Oil Experiment		
	Fracture	Matrix	Fracture	Matrix	
Permeability (md)	4,000	2.47	8,000	2.6	
Initial oil density (g/cm ³)	0.834*	0.834*	0.698**	0.698**	
Gas density (g/cm ³)	0.562*	0.562*	0.699**	0.699**	
Grid dimensions in x-direction (cm)	0.30	0.0829	0.30	0.0820	
Grid dimensions in z-direction (cm)	0.298	0.1125	0.2970	0.1113	
Number of grids in x-direction	1	14	1	14	
Number of grid in z-direction	40	40	40	40	
Initial oil saturation (%)	100	100	100	100	
Initial gas saturation (%)	0	0	0	0	
Separator pressure (bara)	4		4		
Separator temperature (°C)	23		23		
* Reservoir condition at 258.5 bara and 110°C					

** Reservoir condition at 335.9 bara and 100°C

Table 2-The model inputs used in the STO and laboratory-oil numerical models.



Fig. 3—Capillary pressure vs. wetting-phase saturation.

Component	z-STO
N ₂ C ₁	0.00000
CO ₂	0.00000
C ₂	0.00000
C ₃	0.00140
C_4C_5	0.03670
C_6	0.03790
C ₇ C ₁₂	0.43960
C ₁₃ C ₂₀	0.25150
C ₂₁ C ₃₅	0.15580
C ₃₆₊	0.07710

Table 3—The STO composition.

We calculated the initial estimate of diffusion coefficients with the extended Sigmund (1976) correlation by da Silva and Belery (1989). In this study, multicomponent gas/oil-diffusion coefficients were calculated with different compositions at constant pressure and temperature (258.5 bara and 110° C). Ghasemi et al. (2016) provides a detailed description to estimate the porous-media-diffusion coefficients.

Figs. 4a and 4b present the estimated multicomponent diffusion coefficients for different mixtures of CO_2/STO at 258.5 bar absolute and 110°C. As shown in Fig. 4a, oil-diffusion coefficients decrease with increasing amount of CO_2 in the mixtures. This is because of a sharp increase of molar density as more CO_2 dissolves in the mixture. Fig. 4b shows the gas-diffusion coefficients, which are started from 78 mol% of CO_2 , the onset of a two-phase state. All diffusion coefficients shown in Figs. 4a and 4b are the corrected diffusion coefficients in porous media by use of the porosity provided in Table 1 and a cementing factor of 2 (Ghasemi et al. 2016).



Fig. 4—Calculated multicomponent diffusion coefficients for different mixtures of CO_2/STO and $CO_2/n-C_{10}$: (a, b) Oil-diffusion (black) and gas-diffusion (red) coefficients for CO_2/STO mixtures at 258.5 bara and 110°C; (c) oil-diffusion (liquid) coefficient for CO_2 and *n*-C₁₀ for different amount of CO_2 in the mixture at 335.9 bara and 100°C.

In Fig. 4c, we show the liquid (oil)-diffusion coefficients for CO_2/n - C_{10} mixtures at 335.9 bara and 100°C. At this condition, the supercritical CO_2/n - C_{10} mixture is liquid-like and the gas phase does not exist. We present the corrected porous-media-diffusion coefficients by use of cementing factors of 1.5 and 2. As clearly shown in Fig. 4c, the uncertainties concerning petrophysical properties result in a considerable effect on the porous-media-diffusion coefficients.

Matching Experimental Data

In both experiments, the system pressure was kept constant to minimize the viscous forces. Once CO_2 displaced the oil in the fracture, it diffused into the matrix. Consequently, oil swelled and light-to-medium components were vaporized into the gas phase.

It should be noted that the diffusion coefficients were constant input parameters in our simulation models. They were predicted by use of the extended Sigmund (1976) correlation for a range of CO₂/oil mixtures. As expected, higher diffusion coefficients enhance the diffusion mechanism, resulting in rapid oil production, and hence a quicker ultimate oil recovery. Conversely, lower diffusion coefficients result in a slower oil recovery.

We built an automated history matching by integrating preprocessing and post-processing of the simulation results with Pipe-It software (Petrostreamz 2015). The model was run multiple times with different sets of oil/gas-diffusion coefficients. The optimal values of diffusion coefficients were estimated with an optimization algorithm that gives the overall best fit to the experimentally measured data by use of the sum-of-squares (SSQ) objective functions: $F_{SSQ}=\{\Sigma[(Q_{ovm}-Q_{ove})/(Q_{oe,max})^2]\}^{0.5}$, where $Q_{o,m}$ and $Q_{o,e}$ are cumulative oil production given by the numerical model and the experimental result, respectively (Ghasemi et al. 2016). The initial estimate for the oil-diffusion coefficient was at a mixture of 0% CO₂ and 100% STO. Appendix A compares the quality of match for use of extended Sigmund (1976) vs. Wilke and Chang (1955) diffusion coefficients. The result indicates that the initial estimates of diffusion coefficients by use of the extended Sigmund (1976) correlation provide the better performance.

Modeling STO Experiment. One of the main challenges in the modeling is that the reservoir simulator neglects compositional dependency on diffusion coefficients; i.e., the multicomponent diffusion coefficients are assumed to be constant throughout the whole simulation. In the STO experiment, approximately 24.4 PV was injected into the chalk core during 440 hours of CO₂ flooding (see **Fig. 5** for PV_{inj}). We found that when the diffusion time was sufficiently long (i.e., the case with the STO test), the assumption of constant diffusion coefficients may not be truly representative. As shown in Fig. 5, models with constant diffusion coefficients fail to provide a good match with the experimental data. For instance, the case with maximum diffusion coefficients (i.e., oil-diffusion coefficients, D_o , calculated from 100% STO mixture and gas-diffusion coefficients, D_g , calculated from 90% CO₂/10% STO mixture) yields a good match at the early time, but overpredicts the oil recovery after approximately 80 hours. On the other hand, the case with lower diffusion coefficients (D_o calculated from the 60% CO₂/40% STO mixture) matches the data at t > 300 hours but results in a poor match in the early time.



Fig. 5—Measured cumulative oil vs. model for STO test. Blue line shows the model prediction for no-diffusion case. All cases use linear gas/oil relative permeability except the case shown in orange with $n_o = 2$, $n_g = 2$ Corey exponents.

We tried to match the experimental data by modifying gas/oil relative permeabilities. Fig. 5 shows the insignificant effect of using Corey-type relative permeabilities (with exponent $n_o = 2$, $n_g = 2$). It indicates that viscous displacement has a limited significance in oil recovery in the STO experiment. Therefore, we conducted the rest of our simulations with linear gas/oil relative permeabilities. We also ran a case where diffusion was turned off. As shown in Fig. 5, the case without diffusion results in very-low cumulative oil production. This confirms that diffusion between fracture and matrix is the fundamental recovery process in the STO coreflooding experiment. Note that we observed a high oil-production rate of approximately 2.08 cm³/h in the first 0.88 hours, which represented the oil production initially residing in the fracture.

To match the results of the STO experiment, we developed a systematic approach that allows us to define different sets of diffusion coefficients. We divided the simulation into three time frames with separate modeling approaches. First, Model 1 ran from t=0 to $t=t_1$, where measured cumulative oil production was matched by use of the best-fit diffusion coefficients. Second, Model 2 with similar properties as Model 1 ran from $t=t_1$ to $t=t_2$. Model 2 was started with the Model 1 output at t_1 . A different set of diffusion coefficients was used to match the experimental result in this period. Finally, Model 3 ran from $t=t_2$ to the end of the experiment. The best-fit diffusion coefficients at each period represent average diffusion coefficients. Pipe-It software (Petrostreamz 2015) was used to launch and integrate the preprocessing and post-processing applications to merge the model results.

Fig. 6 shows that we are able to obtain a good match between the model and the experimental data when we alter the diffusion coefficients at different times. The successful match suggests that diffusion plays an important role for producing oil from matrix in the STO experiment, and furthermore indicates that the oil-diffusion coefficients change throughout the experiment. **Table 4** shows the estimated (best-matched) oil-diffusion coefficients. Note that the gas-diffusion coefficients were calculated from 90 mol% of CO₂ in the CO₂/STO mixture (Table 3).



Fig. 6—Measured cumulative oil vs. model for Experiment STO-1. Best match is obtained by use of different sets of diffusion coefficients during simulation runs.

	STO Experiment					
	<i>D_{io}</i> (cm ² /h) [*]	<i>D_{io}</i> (cm ² /h) ^{**}	$D_{io} (\mathrm{cm}^2/\mathrm{h})^\dagger$	D _{ig} (cm²/h)		
N_2C_1	0.07841	0.03143	0.00755	0.26510		
CO ₂	0.03847	0.01073	0.00207	0.06041		
C ₂	0.05046	0.02025	0.00489	0.17140		
C ₃	0.03860	0.01552	0.00376	0.13170		
C_4C_5	0.02973	0.01209	0.00293	0.10340		
C ₆	0.02493	0.01016	0.00246	0.08741		
C ₇ C ₁₂	0.01774	0.00802	0.00185	0.06746		
$C_{13}C_{20}$	0.01393	0.00575	0.00134	0.04539		
$C_{21}C_{35}$	0.01020	0.00403	0.00102	0.03024		
C ₃₆₊	0.00784	0.00306	0.00084	0.02302		
* Best match <i>D</i> _{lo} for 0–80 hours (25% CO ₂ in Fig. 4) ** Best match <i>D</i> _{lo} for 80–200 hours (60% CO ₂ in Fig. 4)						

† Best match *D_{io}* for 200–440 hours (D:Min in Fig. 4)

Table 4—Estimated multicomponent diffusion coefficients for STO experiment.

An effort was made to run Models 1, 2, and 3 with diffusion coefficients calculated depending on average composition at intermediate time intervals (middle of t_1 , t_2 , and t_3). As shown by Fig. 6, the calculated diffusion coefficients result in poor performance and are not considered as the representative average diffusion coefficients.

Before the STO laboratory test, a similar experiment was performed where the core plug was not wrapped with the metal foil, which allows molecular diffusion of CO_2 from the matrix into the annulus. Thus, a modeling effort was conducted to simulate the openboundary condition—i.e., including the diffusion of CO_2 into annulus water. It was observed that the oil recovery is barely affected by different boundary conditions. On the basis of the finding, it is recommended to design the CO_2 -injection experiment with a closed boundary to simplify the modeling work flow. It should be noted that the compositional simulator was not able to incorporate modeling of CO_2 diffusion in the aqueous phase, when the oil phase is present.

Modeling Laboratory-Oil Experiment. The laboratory-oil experiment has an experimental setup similar to that of the STO test. The chalk sample contains an axial hole with a diameter of 6 mm that supplies the functionality of a fracture. Matrix and fracture were initially saturated with the laboratory oil that has a density equal to the CO_2 at the experimental conditions. The setup of the experiment was chosen to minimize any gravitational and viscous effects, resulting in a more-precise determination of the diffusion coefficients. The model properties are given in Table 2.

During the experiment, a leakage occurred in the inlet manifold of the rig after 11 hours, which renders the measured CO_2 -injection volume uncertain. The leakage did not affect the downstream part of the experiment, and therefore, the measured volumes of produced gas and oil are reliable. The history matching on oil and gas production was performed by changing both the CO_2/n - C_{10} diffusion coefficient and the CO_2 -injection rate after 11 hours, because the CO_2 -injection rate after this time was not accurately known because of the leakage in the inlet manifold of the rig.

Fig. 4c shows the CO_2/n - C_{10} diffusion coefficients as a function of CO_2 amount in the mixtures. It is shown that there is compositional dependency on the diffusion coefficients. The best-matched diffusion coefficient acts as the "average" or "pseudo" diffusion coefficient for the system because the reservoir simulator neglects the compositional dependency on diffusion coefficients. The quality of the match between the experimental data and the model is shown in **Figs. 7 and 8**.

A good match was obtained by use of a CO_2/n - C_{10} diffusion coefficient of $0.15 \text{ cm}^2/h$ (dashed line in Fig. 4c) and by altering the gas-injection rate after 11 hours, as shown in **Fig. 9**. As shown by Fig. 4c, $0.15 \text{ cm}^2/h$ stays within the acceptable range of compositional-dependent diffusion coefficients for a cementing factor of 1.5. The cementing factor is one of the petrophysical parameters that may vary for different rock properties. For the chalk core used in the laboratory-oil experiment, cementing factor of 1.5 provides a better estimation of diffusion coefficients.



Fig. 7—(a) Pressure-inlet profile and (b) cumulative gas production.



Fig. 8—Model and laboratory cumulative oil-production profile.



Fig. 9—The profile of the gas-injection rate.

An effort was made to back calculate the cumulative CO_2 injection by use of the produced gas data and an estimation of the amount of CO_2 diffused into the matrix and the annulus. As shown in **Fig. 10**, the back-calculated cumulative gas-injection profile (adj. G_{inj} in Fig. 10) is higher than that in the best-matched model.

Fig. 11 shows the recovery-performance comparison between the measured data, the best-matched model, and the adj. G_{inj} model. Both models used the same oil- and gas-phase-diffusion coefficients. The ultimate oil recovery is not affected by the amount of injected CO₂. However, the recovery rate is slightly higher when more CO₂ is injected. This is because of the larger concentration gradient, which leads to higher diffusion flux.

A swelling experiment for the CO_2/n - C_{10} system was simulated by use of the developed CO_2/n - C_{10} Peng-Robinson (Robinson et al. 1979) EOS. It was observed that the mixture of supercritical CO_2 and n- C_{10} is liquid for any proportion of the CO_2 addition (Fig. 12). Thus, we only considered the effect of oil-diffusion coefficients. We studied the effect of oil-diffusion coefficients (D_{io}) by conducting an additional simulation with $D_{io} = 0.1 \text{ cm}^2/h$. Fig. 13 shows that a higher oil-phase-diffusion coefficient results in higher oil recovery.



Fig. 10—Cumulative gas injection for laboratory-oil test.



Fig. 11—Effect of different injection rates on the oil-production profile in laboratory-oil test.



Fig. 12—Liquid saturation and liquid density for CO₂/n-C₁₀ mixture at 335.9 bara and 100°C.

Capillary Pressure and Relative Permeability Effect. We discuss the effect of capillary pressure on the recovery performance of the STO test. Three different capillary pressure data were considered: P_c in this work (base case P_c); P_c reported by Christoffersen (1992); and $P_c = 0$ (Fig. 3). All other properties in the sensitivity runs were kept the same. As shown in **Fig. 14**, capillary pressures may play a major role on the oil recovery. **Fig. 15** illustrates the profiles of gas saturation at 80 and 200 hours for the cases with $P_c = 0$ and base case P_c . Note that we observe significantly different saturation profiles. For $P_c = 0$, CO₂ gas enters the matrix from the top of the fracture by means of gravity and mass transfer. A displacement front between the CO₂ and the oil is developed in the matrix, as shown in Figs. 15a and 15b. As the front moves (Fig. 15b), CO₂ vaporizes more light and intermediate components from the oil and transports them out of the matrix block. A high oil recovery, 82% after 200 hours, is observed. However, for the base case P_c , CO₂ does not enter the matrix at the top of the fracture/matrix boundary because of the high matrix capillary pressure (P_{cgo}). Instead, CO₂ enters the matrix by means of diffusion and gravity forces. When CO₂ enters the matrix, the gas is transferred by the capillary forces toward the right side of the matrix, with the minimum IFT. This effect can be seen in Figs. 15c and 15d. The oil recovery for the base case P_c is 62% after 200 hours (as expected, 20% lower than the case with $P_c = 0$).



Fig. 13—Effect of diffusion coefficients on the performance of laboratory-oil test.



Fig. 14—Effect of capillary pressure on the performance of the STO tests. Model is run for 200 hours.



Fig. 15—Profile of matrix gas saturation and surface tension: (a, b) Gas-saturation profile for $P_c = 0$ at 80 and 200 hours, respectively. (c, d) Profile of gas saturation at 80 and 200 hours for base case P_c . (e) Surface-tension profile for base case P_c at 200 hours. IFT increases toward the top of the matrix near the fracture. Only one-half of the core is shown.

A similar sensitivity study was performed for the laboratory-oil test. Runs with the base case P_c , P_c reported by Christoffersen (1992), and $P_c = 0$ were performed (Fig. 3) to investigate the effect of capillary pressure. Fig. 16 shows negligible effect of different capillary pressures on the recovery. We also performed sensitivity with a modified base case P_c to account for capillary threshold height; P_c ($S_g = 0$) = 0.053 atm. A similar observation is found, as shown by Fig. 16. This is expected, because CO₂ and *n*-C₁₀ are first-contact miscible at the experimental conditions, and hence capillary forces do not have any effect.

To evaluate the effect of the relative permeabilities, we ran various cases by use of the STO model and base case P_c . Different combinations of Corey exponents ($n_o = 2, 4$; $n_g = 2, 4$) and the endpoint relative permeabilities [$k_{rg}(S_g = 1) = 0.2, 0.6$; and $k_{ro}(S_g = 0) = 0.2, 0.6$] were considered. **Fig. 17a** shows the negligible effect of relative permeabilities on the oil recovery. This ensures that the convective flow barely exists in the matrix (a detailed discussion on convective flow will be addressed later). However, when $P_c = 0$, the oil recovery depends more on gas-endpoint relative permeability rather than in Corey exponents (Fig. 17b). As shown by Fig. 17b, we find that the oil recovery is strongly affected by both oil Corey exponents and the oil relative permeability endpoints when no capillary pressure exists ($P_c = 0$).



Fig. 16—Effect of capillary pressure on the laboratory-oil performance.



Fig. 17—Effect of oil relative permeability on the oil-recovery STO test: (a) base case P_c ; (b) $P_c = 0$.

Convective Flow and Physical Dispersion. To evaluate the relative importance of convective flow over diffusion, the Péclet number (N_{Pe}) in dimensionless form is used:

$$N_{\rm Pe} = \frac{uL}{K_{\ell}}.$$
 (1)

Perkins and Johnston (1963) define the following relation for K_{ℓ} :

 $K_{\ell} = D + \alpha u. \qquad (2)$

Perkins and Johnston (1963) gave an average longitudinal dispersivity of 0.18 cm (0.006 ft) for sandstone, which was used in this work. The transverse dispersivity is 30 times less and was not addressed in this study. Eq. 2 was reformed as the following relation to identify the relative importance of total dispersion over molecular-diffusion coefficients (Jha et al. 2008, Perkins and Johnston 1963):

$$\frac{K_{\ell}}{D} = 1 + \frac{\alpha u}{D}. \tag{3}$$

The Péclet number in Eq. 1 is a conventional definition for binary-component single-phase flow in 1D porous media. Hoteit and Firoozabadi (2009) presented the modified form of Eq. 1 for 2D multicomponent two-phase flow. In their definition, the Péclet number was locally evaluated for each phase present in a grid cell. The grid-cell properties (e.g., compositions and their associate fluid properties) were collected and used to determine local diffusion coefficients by use of the extended Sigmund (1976) correlation. We calculated the matrix Péclet number for both STO and laboratory oil at 1.5 cm away from the fracture and after 1 PV_{inj}. **Fig. 18a** presents the $N_{\rm Pe}$ along the chalk core for STO and the laboratory oil. At 1 PV_{inj}, the fracture was filled with gas and the matrix grid cells (1.5 cm away from the fracture) were fully saturated with oil. Therefore, Fig. 18a shows the $N_{\rm Pe}$ for the gas phase in the fracture and for the oil phase in the matrix. As shown by Fig. 18a, the average matrix $N_{\rm Pe}$ along the chalk core is approximately 0.002, which indicates that the transport mechanism is dominated by dispersion rather than convective flow. The term K_ℓ/D in Eq. 3 is 1.009, which clearly shows that the total dispersion is covered by diffusion rather than the physical dispersion. To identify the type of convective flow in the matrix, the following dimensionless ratio was used to evaluate the importance of the viscous force vs. the gravity force (Wylie and Mohanty 1999):

$$R_{\nu/g} = \frac{\Delta P_{\rm vis}}{\Delta P_{\rm oray}} = \frac{\mu\mu_o}{kg\Delta\rho}.$$
(4)

The calculated $R_{v/g} = 0.21$ reveals that the gravity force is five times higher than the viscous force. Therefore, as shown by Fig. 5, the 15% oil recovery for the case without diffusion is gained considerably by gravity drainage.



Fig. 18—Calculated Péclet Number (*N*_{Pe}): (a) STO; (b) laboratory-oil.

We also investigated the possible presence of a convection mechanism by setting a zero matrix vertical permeability (k_v) . The results of the $k_v = 0$ case were compared with the base-case model. Similar recovery performance was observed, proving an inconsiderable presence of convection mechanism in the matrix of the STO test experiment. However, high velocity contrast exists between the oil phase in the matrix and the gas phase in the fracture. The average $N_{\rm Pe} = 1$ for the gas phase in the fracture marks the considerable presence of convective flow.

Fig. 18b shows the laboratory-oil Péclet number for the liquid phase in the matrix and the fracture. As discussed previously, the mixture of supercritical CO₂ and n-C₁₀ is liquid phase at reservoir condition. The average N_{Pe} is 0.001 for the matrix and 0.08 for the fracture, proving negligible presence of convective flow in both distinct media. Moreover, the matrix K_{ℓ}/D is 1.005, which again shows that the diffusion is dominant over physical dispersion. The fracture Péclet number decreases with height because of a significant amount of CO₂ near the injector, which results in larger diffusion coefficient and hence lower N_{Pe} . This evaluation confirmed our main objective of using n-C₁₀ to minimize the convective transport and hence create a diffusion-dominated displacement.

We simulated a case with zero matrix vertical permeability (k_v) . As shown by **Fig. 19**, we observe a similar oil-recovery profile for the base case and the case with $k_v = 0$. Moreover, **Fig. 20** illustrates similar density distributions for both models at different simulation times. This indicates that the convective effects are negligible during the experiment. The absence of the capillary forces and the convective effects suggests that the displacement is dominated solely by the diffusion.



Fig. 19—Calculated Péclet Number (N_{Pe}): (a) STO; (b) laboratory-oil.

Conclusions

The main conclusions from this work are the following.

- 1. A series of core experiments were successfully conducted to study the effect of diffusion at the reservoir conditions. The experiments were numerically modeled and successfully history matched. This confirms the validity of our work flow because it incorporated a representative EOS model and the relevant transport mechanisms, including properly represented diffusive flux.
- 2. On the modeling of CO_2 injection, when diffusion is the main mechanism, it is important to select a set of D_{oi} and D_{gi} that represents the system. The recommended approach is to calculate the initial D_i by use of available correlations. We found that the extended Sigmund (1976) correlation provides better estimation compared with other correlations [e.g., the Wilke and Chang (1955) correlation].
- 3. It was shown that when PV_{inj} is high enough (PV_{inj} >10), and the average composition in chalk is altered because of increased amount of CO₂, the numerical models with the assumption of constant diffusion coefficients may not properly capture the real physics of molecular diffusion. This is because of the compositional dependency of D_i .
- 4. We successfully reduce the convective effects and the capillary forces by use of a CO₂/*n*-C₁₀ fluid system. Because the diffusion is the sole displacement mechanism for this specific experiment, the methodology is validated for accurate estimation of the diffusion coefficients.



Fig. 20—Map of the oil density in the matrix: (a) case with $k_v = 2.6$ md and (b) case with $k_v = 0$ md at 50 hours; and (c) case with $k_v = 2.6$ md and (d) case with $k_v = 0$ md at the end of the test at 130 hours. Values are in g/cm³. Only the half of the core is shown.

Nomenclature

- D =norm of the multicomponent diffusion coefficients
- $D_{g} = \text{gas-diffusion coefficients}, L^{2}/t, \text{cm}^{2}/h$
- $D_o = \text{oil-diffusion coefficients, } L^2/t, \text{ cm}^2/h$
- g = gravity-acceleration constant
- k = matrix-block permeability
- $K_{\ell} =$ longitudinal dispersion coefficients
- L = grid-cell characteristic length in the direction of the maximum velocity u
- $M_{g} = \text{gas molecular weight}$
- M_o = oil molecular weight
- n_g = Corey-type relative permeabilities for gas
- n_o = Corey-type relative permeabilities for oil
- N = number of grid cells
- $p = \text{pressure, m/Lt}^2$, bara
- $p_c = \text{critical pressure, m/Lt}^2$, bara
- $P_c = \text{capillary pressure, m/Lt}^2$, bara
- $S_g =$ gas saturation, fraction
- S_o = oil saturation, fraction
- T =temperature, °C
- T_c = critical temperature, K
- u = Darcy velocity, L/t, cm/h
- u = maximum direction velocity in *r* or *z*-direction, L/t, cm/h
- z_i = amount of mole fraction of component *i* in cell
- α = physical dispersivity
- $\mu_o = \text{oil viscosity}$

- $\rho_{g} = \text{gas density, m/L}^{3}, \text{g/cm}^{3}$ $\rho_{o} = \text{oil density, m/L}^{3}, \text{g/cm}^{3}$ $\sigma = \text{gas/oil IFT, m/t}^{2}, \text{dynes/cm}$
- $\omega = \text{acentric factor}$

Acknowledgments

We would like to thank the Joint Chalk Research Consortium for permission to publish this work and providing financial support for this study and a series of our CO₂ EOR research projects in the North Sea. The Joint Chalk Research Consortium consists of Norwegian Petroleum Directorate, Danish Energy Agency, Danish North Sea Fund, BP, ConocoPhillips, Dong, Eni, Hess, Mærsk Oil, Shell, Statoil, and Total.

References

- Alavian, S. A. and Whitson, C. H. 2010. CO₂ EOR Potential in Naturally Fractured Haft Kel Field, Iran. SPE Res Eval & Eng 13 (4): 720–729. SPE-139528-PA. https://doi.org/10.2118/139528-PA.
- Christoffersen, K. R. 1992. High-Pressure Experiment with Application to Naturally Fractured Chalk Reservoir. PhD dissertation, Norwegian University of Science and Technology, Trondheim, Norway.
- Coats, K. H. 1989. Implicit Compositional Simulation of Single-Porosity and Dual-Porosity Reservoirs. Presented at SPE Symposium on Reservoir Simulation, Houston, 6-8 February. SPE-18427-MS. https://doi.org/10.2118/18427-MS.
- da Silva, F. V. and Belery, P. 1989. Molecular Diffusion in Naturally Fractured Reservoirs: A Decisive Recovery Mechanism. Presented at the 64th SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 8-11 October. SPE-19672-MS. https://doi.org/10.2118/SPE-19672-MS.
- Darvish, G. R. 2007. Physical Effects Controlling Mass Transfer in Matrix Fracture System During CO2 Injection into Chalk Fractures Reservoirs. PhD dissertation, Norwegian University of Science and Technology, Trondheim, Norway.

- Darvish, G. R., Lindeberg, E. G. B., Holt, T. et al. 2006. Reservoir Conditions Laborator Experiments of CO₂ Injection into Fractured Cores. Presented at the 2006 SPE Europec/EAGE Annual Technical and Exhibition, Vienna, Austria, 12–15 June. SPE-99650-MS. https://doi.org/10.2118/99650-MS.
- Ghasemi, M., Astutik, W., Alavian, S. A. et al. 2016. Determining Diffusion Coefficients for Carbon Dioxide Injection in Oil-Saturated Chalk by Use of a Constant-Volume-Diffusion Method. *SPE J.* 22 (2): 505–520. SPE-179550-PA. https://doi.org/10.2118/179550-PA.
- Grigg, R.B. 2000. Experimental Investigation of CO₂ Gravity Drainage in a Fractured System. Presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Brisbane, Australia, 16–18 October. SPE-64510-MS. https://doi.org/10.2118/64510-MS.
- Hoteit, H. and Firoozabadi, A. 2009. Numerical Modeling of Diffusion in Fractured Media for Gas-Injection and -Recycling Schemes. SPE J. 14 (2): 323–337. SPE-103292-PA. https://doi.org/10.2118/103292-PA.
- Jha, R. K., Bryant, S. L., and Lake, L. W. 2008. Effect of Local Mixing on Dispersion. Presented at the 2008 SPE Annual Technical Conference and Exibition, Denver, 21–24 September. SPE 115961-MS. https://doi.org/10.2118/115961-MS.
- Le Romancer, J. F., Defives, D., Kalaydjian, F. et al. 1994. Influence of the Diffusion Gas on the Mechanism of Oil Recovery by Gas Diffusion in Fractured Reservoir. Oral presentation given at the IEA Collaborative Project on Enhanced Oil Recovery Workshop and Symposium, Bergen, Norway, 28–31 August.
- Moortgat, J., Firoozabadi, A., Li, Z. et al. 2013. CO₂ Injection in Vertical and Horizontal Cores: Measurements and Numerical Simulation. *SPE J.* **18** (2): 331–344. SPE-135563-PA. https://doi.org/10.2118/135563-PA.
- Morel, D. D., Bourbiaux, B., Latil, M. et al. 1990. Diffusion Effects in Gas Flooded Light Oil Fractured Reservoirs. Presented at the 65th SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September. SPE-20516-MS.
- Perkins, T. K. and Johnston, O. C. 1963. A Review of Diffusion and Dispersion in Porous Media. SPE J. 3 (1): 70-84. SPE-480-PA. https://doi.org/ 10.2118/480-PA.
- Petrostreamz. 2015. Pipe-It User Manual, Version 1.5.2. Trondheim, Norway: Petrostreamz.
- Robinson, D. B., Peng, D. Y., and Ng, H. Y. 1979. Capabilities of the Peng-Robinson Programs, Part 2: Three-Phase and Hydrate Calculations. *Hydrocarb. Process.* 58: 269.
- Schlumberger. 2012. ECLIPSE 300 User Manual, Version 2012.1. Houston, Texas: Schlumberger.
- Sigmund, P. M. 1976. Prediction of Molecular Diffusion at Reservoir Condition. Part 1-Measurement and Prediction of Binary Dense Gas Diffusion Coefficients. *J Can Pet Technol* **15** (2): 53–62. PETSOC-76-02-05. https://doi.org/10.2118/76-02-05.
- Simon, R., Rosman, A., and Zaba, E. 1978. Phase-Behavior Properties of CO₂-Reservoir Oil Systems. SPE J. 18 (1): 20–26. SPE-6387-PA. https://doi.org/10.2118/6387-PA.
- Wilke, C. R. and Chang, P. 1955. Correlation of Diffusion Coefficients in Dilute Solution. AIChE J. 1 (2): 264–270. https://doi.org/10.1002/aic.690010222.
- Wylie, P. L. and Mohanty, K. K. 1999. Effect of Wettability on Oil Recovery by Near-Miscible Gas Injection. SPE Res Eval & Eng 2 (6): 558–564. SPE-59476-PA. https://doi.org/10.2118/59476-PA.

Appendix A—Performance of Diffusion Correlation at Initial Guess

Fig. A-1 shows the quality of match for initial estimate of oil-diffusion coefficients at 0% CO₂/100% STO mixture by use of the extended Sigmund (1976) and Wilke and Chang (1955) diffusion correlations. The extended Sigmund (1976) correlation results in better performance compared with the Wilke and Chang (1955) diffusion correlation.



Fig. A-1—Quality of fit by use of different diffusion correlations at initial guess.

Mohammad Ghasemi is senior reservoir engineer at Petrostreamz A/S. Previously, he worked for the National Iranian South Oil Company and PERA as a reservoir engineer. Ghasemi has been involved in vast range of reservoir-engineering projects. His research interests include EOR for conventional and unconventional reservoirs, fluid characterization and EOS modeling, reservoir simulation, and integrated optimization. Ghasemi earned bachelor's and master's degrees in petroleum engineering from the Petroleum University of Technology, Iran, and holds master's and PhD degrees from the University of Calgary and the Norwe-gian University of Science and Technology (NTNU), respectively, both in petroleum reservoir engineering. He is a member of SPE.

Wynda Astutik is a senior reservoir engineer at Petrostreamz A/S. Previously, she worked at Chevron with main responsibilities on steam huff 'n' puff and waterflooding optimization. Astutik's research interests include reservoir modeling, fluid behavior, and integrated asset modeling and optimization. She holds a bachelor's degree from Bandung Institute of Technology, Indonesia, and a master's degree from NTNU, both in petroleum engineering.

Sayyed Ahmad Alavian is senior reservoir engineer at PERA. His research interests include PVT and gas-injection EOR. Alavian has authored or coauthored more than eight technical papers. He holds a PhD degree in reservoir engineering from NTNU. Alavian is a member of SPE.

Curtis H. Whitson is professor of petroleum engineering at the Department of Petroleum Engineering and Applied Geophysics at NTNU. He teaches courses on petroleum phase behavior, EOR, well performance, gas-reservoir engineering, and integratedmodel optimization. Whitson coauthored *Well Performance* (second edition, Prentice Hall, 1991) and Volume 20 of the SPE Monograph Series, *Phase Behavior*. He consults extensively for the petroleum industry through PERA, a specialty consulting company he founded in 1988. Whitson holds a bachelor's degree in petroleum engineering from Stanford University and a PhD degree from the Norwegian Institute of Technology (now NTNU). He is a 28-year member of SPE, has twice received the SPE Cedric K. Ferguson Young Technical Author Medal (as coauthor with Øivind Fevang in 1997 and with Lars Høier in 2001), and received the 2011 SPE Anthony F. Lucas Gold Medal.

Lykourgos Sigalas is a research assistant at the National Geological Survey of Denmark and Greenland (GEUS). His current interests include EOR and well-integrity laboratory experiments. Sigalas holds a BSc degree in engineering in petroleum and natural gas technology from the Technological Educational Institute of Kavala and a master's degree in petroleum engineering from the Technical University of Denmark.

Dan Olsen is senior petrophysicist at GEUS and is head of the GEUS Core Analysis Laboratory. He has worked with core analysis for 31 years, the last 20 years with particular focus on flooding experiments at reservoir conditions. Olsen holds a master's degree in petrology from the University of Copenhagen, Denmark.

Vural Sander Suicmez is a Lead Reservoir Engineer with Maersk Oil in Copenhagen, Denmark. Before joining Maersk, he worked at Brunei Shell Petroleum in Seria, Brunei Darussalam; Shell Global Solutions International in Rijswijk, The Netherlands; and at Saudi Aramco's EXPEC Advanced Research Center in Dhahran, Saudi Arabia. Suicmez specializes in well, reservoir and facility management (WRFM), multiphase flow in porous media, and enhanced oil recovery (EOR) mechanisms. He has authored or coauthored more than 30 technical papers. Suicmez holds bachelor's, master's, and PhD degrees, all in petroleum engineering, from Middle East Technical University, Stanford University, and Imperial College London, respectively, as well as an MBA degree from the University of Cambridge, UK. He currently serves as the Editor-in-Chief for Elsevier's Journal of Petroleum Science and Engineering and as an associate editor for the SPE Journal. Suicmez is a member of the SPE Reservoir Description and Dynamics Award Committee.