

# NEW APPROACH IN GAS INJECTION MISCIBLE PROCESSES MODELING IN COMPOSITIONAL SIMULATION

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## ABSTRACT

*A number of factors must be considered in the design of miscible displacement processes.*

*This paper discusses a new approach that relates primarily to the laboratory and modeling studies that precede the EOS based compositional simulation of reservoir performance during the vaporizing/condensing gas drive process.*

*The phase behavior of a solvent/oil system and determination of miscibility conditions by various special PVT experiments including swelling test, RBA, slim tube test and continuous multiple-contact experiment are reviewed along with their importance in building an accurate EOS model to be used in compositional simulation. In addition to experimental PVT data, a special core flow test design for measuring the relative permeabilities to generated fluids by forward/reverse multiple contact experiments is discussed.*

*Based on laboratory PVT and SCAL data, a novel interfacial tension-dependent model of relative permeability and capillary pressure data is presented along with the advantages if incorporated in the commercial EOS based compositional simulation software packages.*

## INTRODUCTION

Mass transfer between the gas and oil components dominates the displacement characteristics of miscible or near-miscible floods. The overall displacement efficiency on any oil recovery displacement process can be considered conveniently as the product of microscopic and macroscopic displacement efficiencies. In equation form,

$$E = E_D E_V \quad (1)$$

where  $E$  = overall displacement efficiency,  $E_D$  = microscopic displacement efficiency, and  $E_V$  = macroscopic (volumetric) displacement efficiency.

Microscopic displacement relates to the displacement or mobilization of oil at pore scale. That is,  $E_D$  is a measure of effectiveness of the displacing fluid in moving (mobilizing) the oil at those places in the rock where the displacing fluid contacts the oil.  $E_D$  is reflected in magnitude of the residual oil saturation,  $S_{or}$ , in the regions contacted by the displacing fluid.

Macroscopic displacement efficiency relates to the effectiveness of the displacing fluid(s) in contacting the reservoir in a volumetric sense.  $E_V$  is a measure of how effectively the displacing fluid sweeps out the volume of a reservoir, both areally and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells. It is desirable in an EOR process that the values of  $E_D$  and  $E_V$  and consequently  $E$ , approach 1. An idealized EOR process

would be one in which the displacing fluid removed all oil from the pores contacted by the fluid ( $S_{or} \rightarrow 0$ ). Several physical/chemical interactions occur between the displacing fluid and the oil that can lead to efficient microscopic displacement (low  $S_{or}$ ). These include miscibility between the fluids, decreasing the IFT between the fluids, oil volume expansion, and reducing oil viscosity. The maintenance of a favorable mobility ratio between displaced and displacing fluids also contributes to better microscopic displacement efficiency. EOR processes are thus developed with consideration of these factors. The goal with an acceptable EOR fluid is to maintain the favorable interaction(s) as long as possible during the flooding process.

In enhanced recovery operations, oil entrapment occurs due to complex interactions between viscous, gravity and capillary forces. Enhancing recovery from fields typically involves altering the relative importance of the viscous and capillary forces. The capillary number, which is defined as the ratio of viscous forces to capillary forces, provides the basic expression of the relative importance of these forces. The capillary number depends on the velocity, viscosity and interfacial tension of the wetting fluid and is commonly defined as

$$N_c = \frac{u\mu}{\sigma} \quad (2)$$

Most displacement processes are designed to increase the viscous forces and/or reduce the capillary forces in order to reduce the residual oil saturation and increase the oil recovery. Many authors<sup>1-4</sup> have studied the effect of capillary number on normalized residual oil saturation at the core scale. The relationship is typically shown through a capillary desaturation curve as shown schematically in Fig. 1. These curves typically show a normalized residual oil saturation plateau region from very low capillary numbers after which normalized residual oil saturations drop with increasing capillary number. The point at which normalized residual oil saturation starts to drop with increasing capillary number is called the critical capillary number. The critical capillary number varies from reservoir to reservoir due to numerous factors such as rock structure, rock wettability, test conditions and fluid types and fluid phase behavior.

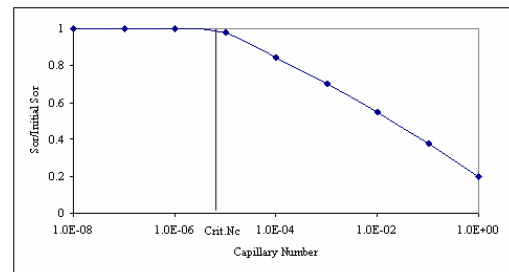


Fig. 1 Residual Oil Saturation vs. Capillary Number

Several authors<sup>8</sup> have found critical capillary numbers much lower for continuous oil (connected oil) than discontinuous oil (disconnected oil) because the force required to mobilize this trapped oil is much larger for the discontinuous oil than continuous oil. Further, when

systems move from strongly water-wet to intermediate wettability, viscous forces required to reduce the residual oil saturation drops.

## PVT LABORATORY PROTOCOL

### PVT Sampling

The value of the reservoir fluid PVT study depends on the quality of the fluid samples obtained. Three common methods are used to sample the reservoir fluid.

**Bottomhole Sampling.** A fluid sample at a flowing bottomhole pressure greater than the saturation pressure of the fluid so that the sample is a single phase.

**Wellhead Sampling.** A fluid sample at flowing wellhead conditions so that the sample is a single phase.

**Separator Sampling.** A fluid sample obtained by recombining the separator liquid and separator gas taken at the measured gas-oil ratio (GOR). The separator gas and liquid sometimes are recombined to a target reservoir saturation pressure rather than to the measured GOR.

### Reservoir Fluid PVT Study

The appropriate PVT experiments are related closely to the processes implemented in the field. The overall purpose of reservoir fluid studies is to provide basic volumetric, phase and viscosity data of reservoir fluids. Normally, the Reservoir Fluid PVT Study consists of Constant Composition Expansion (CCE), Differential Liberation (DL) or Constant Volume Depletion (CVD), and Fluid Viscosity Study (FVS). In some cases, a multi-stage separator test (MSS) is also performed. The conversion of differential data to flash data is very important. Otherwise, using the oil-formation-volume factor curve from the differential liberation instead of the flash-formation-factor curve can lead to errors in calculation of oil in place (OIP) and recoverable oil. These data may be utilized to aid in the analysis of past and future behavior of the reservoir to generate reliable fluid properties for use in reservoir simulation. A schematic of standard PVT laboratory tests is shown in Fig. 2.

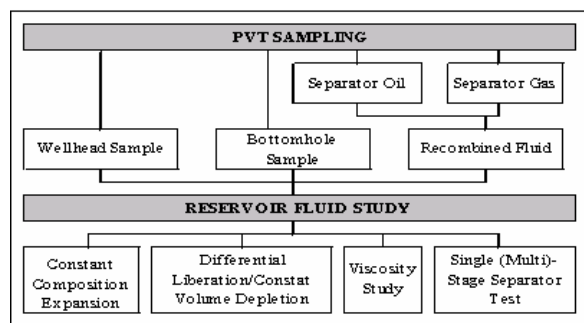


Fig. 2 Reservoir Fluid Study – Laboratory Protocol

### Reservoir Fluid Miscibility Study

The thermodynamic conditions required for dynamic miscibility with injection gas, as well as the gas composition are best determined by laboratory experiments. The most common experiments conducted to determine the miscibility conditions are shown schematically in Fig. 3:

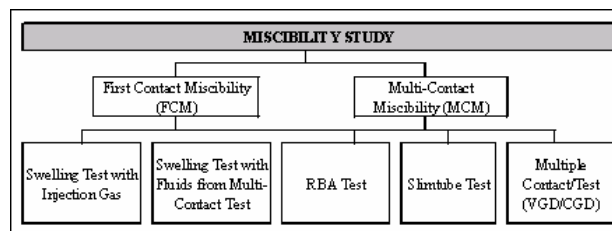


Fig. 3 Miscibility Study – Laboratory Protocol

#### Swelling Test (P-x) with Injection Gas

The swelling test is the most common PVT experiment for first-contact miscibility studies. This experiment provides information on the gas injection fluid behavior as function of pressure at reservoir temperature. When a gas is injected into a reservoir, it can go into solution and swells the oil; i.e. the volume of the oil becomes larger. A Constant Composition Expansion (CCE) experiment and Fluid Viscosity Study (FVS) may be performed for each mixture of injection gas and oil in the above process. The data are generally presented in a pressure – composition (P-x) and main PVT single-phase property vs. injection gas addition diagram. The PVT data provided include saturation pressure, oil density, fluid formation volume factor, gas-oil ratio, swelling factor, oil viscosity, and the fluid composition at each addition.

#### Rising Bubble Apparatus Experiment

The Rising Bubble Apparatus (RBA) miscibility test is a rapid and accurate technique (as well as cost-effective) to provide approximate first contact and multiple-contact minimum miscibility pressures (MMP) for oil - injection gas mixtures. Usually MMP from RBA is higher than apparent MMP obtained by slim tube tests but is often lower than that determined by multiple contact tests with explicit IFT measurements.

#### Slim tube Experiment

The MMP from RBA test is a good starting pressure for the slim tube experiments in order to reduce the runs for the MMP determination. Normally four runs are sufficient for determination of slim tube test MMP by calculating the intersection point between the line of high recovery and the line of low recovery after 1.2 PV of solvent injection. An additional slim tube test may be performed at this pressure for confirmation purposes.

#### Multiple Contact Experiment

Multiple Contact experiments are performed to generate quasi-statically the complete range of compositions and interfacial tensions that will be generated dynamically in the reservoir under injection conditions. The multiple contact tests are normally performed at the MMP determined from RBA, slim tube tests or at reservoir pressure. For a better understanding of phase behavior and miscibility conditions, multiple contacts at different pressures are recommended.

The multi-contact test procedure starts by mixing the original injection gas and original reservoir oil at operating pressure. Thereafter the procedures for vaporizing gas drive (forward contacting) and condensing gas drive (reverse contacting) are different.

Normally, three forward contacts and three reverse contacts are sufficient to determine if the mechanism is a vaporizing, condensing or condensing/vaporizing one. The experimental data include interfacial tension (IFT), viscosity, fluid formation volume factors, gas-oil ratio, K-Values and the compositions of each phase at each contact.

*Swelling Test (P-x<sub>mc</sub>) with Forward-Contacted Injection Gas*

The swelling test (P-x) – oil with forward-contacted injection gas has the same basic procedure as the swelling test (P-x) with injection gas. The only difference was that in this case the solvent was the forward-contacted injection gas obtained from the multiple contact tests. Because of higher mobility of injection gas, the gas in contact with original fluid has been in contact before with original fluid and its composition has changed. The swelling test with forward-contacted injection gas investigates the asymptotic richest gas as it interacts with reservoir fluid on the leading edge of the displacement, while first contact miscibility normally is achieved at a lower pressure, so the saturation pressure curves shift to lower pressures as shown in Fig. 4 in case of swell test with lean gas. The PVT data reported are as described in conventional swelling test.

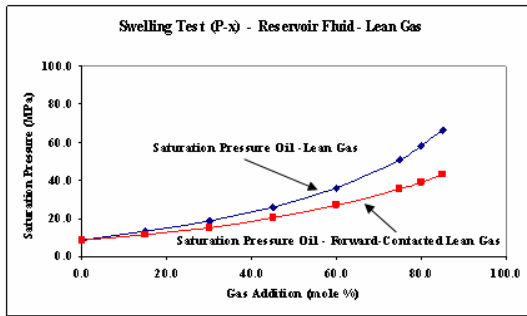


Fig. 4 Swelling Test (P-x) – Reservoir Fluid-Lean Gas

*Swelling Test (P-x<sub>mc</sub>) Reverse-Contacted Oil with Injection Gas*

Swelling Test (P-x<sub>mc</sub>) Reverse-Contacted Oil with Injection Gas has the same basic procedure as the swelling test (P-x) with injection gas. The only difference was that in this case the fluid was the reverse-contacted oil obtained from the multiple contact tests. The swelling test of reverse-contacted oil with injection gas investigates the interaction gas-oil near the injection zone. The first contact miscibility normally is achieved at a higher pressure, so the saturation pressure curves shift to higher pressures as shown in Fig. 5 in case of swell test with enriched gas. The PVT data reported are as described in conventional swelling test.

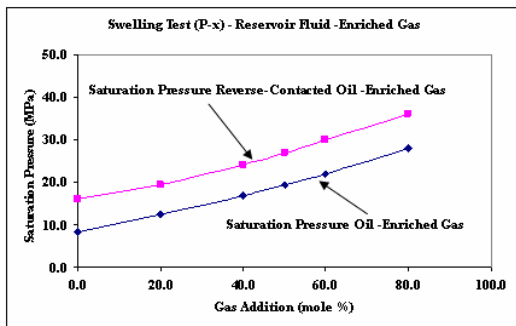


Fig. 5 Swelling Test (P-x) – Reservoir Fluid-Enriched Gas

**EOS CHARACTERIZATION AND MODELING**

The use of EOS simulation becomes even more effective when the process involves gas injection for miscible or near-miscible displacement of the oil in reservoirs.

When the displacement process depends on pressure and fluid composition, an EOS should be used to simulate the equilibrium mass

transfer between phases and PVT behavior of the fluids. PVT laboratory measurements are made on only a small portion of the composition path encountered throughout the displacement, whereas an EOS can be used to predict behavior for the entire composition path and pressure range of the process.

The accuracy of any EOS model depends on the quality of the laboratory PVT data and procedures used to obtain the EOS parameters. The PVT data from the experiments described above can be used as input to tune an EOS model for a compositional simulation purposes.

EOS characterization and modeling of measured PVT data are very important for the precise evaluation and prediction of the reservoir performance. The accuracy of EOS characterization will depend on the type of data available. For best results a data set exhibiting both volatility and extraction data is required<sup>5-6</sup>. The main objective of EOS modeling is an accurate prediction of fluid behavior in the entire P-V-μ envelope at reservoir temperature. Generally the results of an EOS model must be tuned by nonlinear regression of one or more variables.

The P-V-μ envelope at reservoir temperature is mostly determined by matching the data from Reservoir Fluid Study. The gas injection processes increase the variables that have to be matched with measured PVT data from Miscibility Study. By tuning the EOS to match the data from swelling test, multiple contact test with injection gas and from swelling test with multi-contacted injection gas the upper and lower saturation pressure curves with respect to gas additions is simulated. Using the EOS model as described above laboratory slim tube displacements can be evaluated using a compositional simulator.

**CORE LABORATORY PROTOCOL**

The MMP determined by slim tube tests has been accepted by the oil industry as the target reservoir pressure for designing a miscible process and the effluent composition vs. pressure provided also from this test can be used for EOS modeling. However, slim tubes have a “porous medium” which bears little resemblance to reservoir rocks and water is not present during the test. Therefore, routine core analysis (RCAL) and special core analysis (SCAL) are the main sources of data to guide the reservoir engineer in assessing the reservoir performance.

**Routine Core Analysis** attempts to give only the very basic properties of unpreserved core. These are basic rock dimensions, core porosity, grain density, gas permeability, and water saturation. Taken in context routine data can provide a useful guide to well and reservoir performance, provided its limitations are appreciated. A schematic diagram of common RCAL measurements is given in Fig. 6.

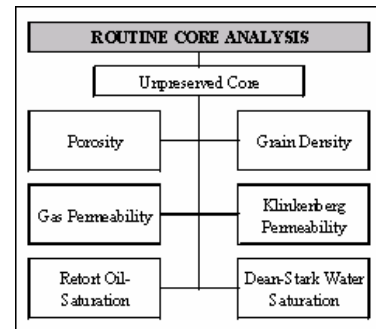


Fig. 6 Routine Core Analysis

**Special Core Analysis** attempts to extend the data provided by routine measurements to situations more representative of reservoir conditions. Tests are carried out to measure fluid distribution, electrical properties and fluid flow characteristics in the two and occasionally

three phase situation, and are made on preserved core. A schematic diagram of common SCAL measurements is given in Fig.7.

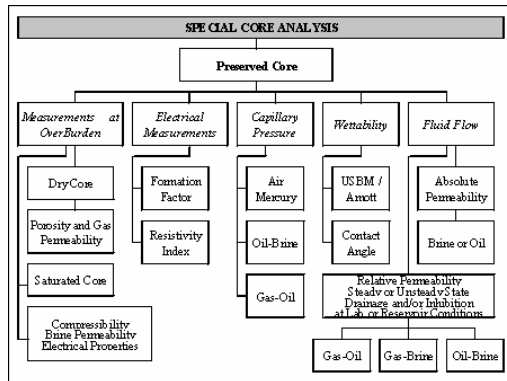


Fig. 7 Special Core Analysis

The saturation axis of the capillary pressure and relative permeability, combined with knowledge of porosity, reflects the original in place and movable hydrocarbon volumes. The shapes of the relationships, and particularly the endpoint properties, have a major influence on predictions of how effectively water or gas displaces oil in a reservoir (microscopic displacement and sweep efficiencies). For this reason, core-measured capillary pressure and relative permeability data are regarded as highly important, and are typically applied at the outset of fine scale model development.

In this paper, the relative permeability properties measurements in case of miscible displacements as key input data for compositional reservoir simulation models will be discussed in more detail.

### Relative Permeability

Relative permeability experiments attempt to provide data on the relative flow rates of phases present (e.g. oil and water or gas and water). Fluid flow is strongly influenced by fluid viscosities, and wetting characteristics. The data generated allows relative flow rates and recovery efficiency to be assessed.

The reservoir engineer should be concerned with sufficient details of measuring and interpreting relative permeability data to recognize its overall validity for the simulation model.

Relative permeability information is best derived from displacement tests on a suite of samples representing the principal reservoir rock types or facies. Alternatively, tests are performed on samples covering the permeability range of the reservoir. The relative permeability data so obtained are typically averaged to establish relative permeability characteristics representative of each reservoir facies or permeability range. Coupling these measurements with fluid phase behavior will quantify the boundaries during miscible displacements.

For this purpose, the relative permeability experiment at Constant Interfacial Tension (IFT), i.e., at the maximum and minimum interfacial tension conditions that will be generated in the reservoir during a gas injection process are performed to quantify the limits for the relative permeability curves expected to be achieved.

Accordingly, the equilibrium high and low interfacial tension fluid pairs, which are the end products of the multiple contact miscibility studies, are used as the baseline fluids to conduct these special relative permeability experiments. Since the fluids are the equilibrium condition, no mass transfer will occur between the gas and oil phase,

making them ideal displacement fluids for relative permeability experiments where the only parameter varied is the interfacial tension level.

A sample of preserved or restored state core is generally utilized for these experiments (with the exact same sample used for both the high and low IFT extremes). Generally, a full diameter sample is used to maximize the pore volume and improve the accuracy of the experimental protocol. The correct restoration of wettability and the selection of the appropriate facies and rock types for the displacements are essential. If multiple, significantly different, lithological flow units are present within the reservoir, it may be necessary to conduct a set of constant interfacial tension relative permeability experiments on each separate facies to obtain an accurate evaluation of the displacement efficiency of the potential gas injection process.

Wettability and pore size distribution may significantly impact recovery performance. An example of this situation is shown in Fig. 8 (Case A) where the rock exhibits a wide pore size distribution and a large fraction of the oil in place is trapped and contained in a relatively small pore space with small pore throat radii. This could be associated with the type of formation, but most commonly would occur in an oil-wet situation where low initial water saturation is present and the large portion of the pore space is effectively saturated with liquid hydrocarbons. Since the pore throats which can be effectively accessed by the injected solvent are a direct function in the capillary pressure which, in turn, is a function of the interfacial tension between the phases, one can see that in order to effectively access and sweep a large portion of the reservoir volume encompassed by the small pore system, we must generate a very low interfacial tension in order to obtain a high recovery factor.

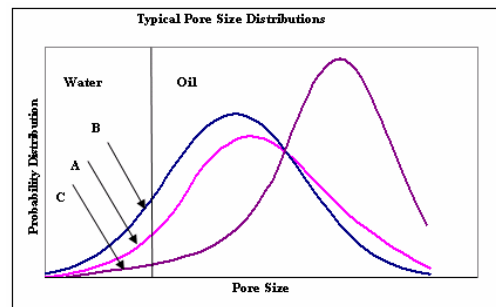
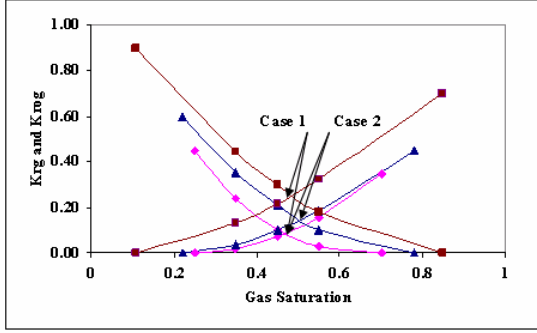


Fig. 8 Typical Pore Size Distributions

If the same pore size distribution (Fig.8, Case B), but in a strongly water-wet situation, then in this case, we consider that a large portion of the micro-porosity is saturated with water rather than oil and represents pore space that is not necessary to penetrate in order to achieve significant recovery of the oil in place in the reservoir. In this example, one can observe that a much higher interfacial tension condition could be used to obtain a comparable overall recovery factor to the preceding situation.

Another situation is, where a skewed pore size distribution is present and a large portion of the recoverable oil is contained in macropores with very little micro-porosity (Fig.8, Case C). Once again, one can observe that a relatively high interfacial tension can result in effective recovery of a large portion of the oil in-place in the reservoir. Other factors which may adversely influence recovery in such a case would be viscosity and mobility ratio as well as gravity override effects, since reservoirs with these types of size distributions are often characterized by large interconnected vugs or fractures or other macroporous features which may create high permeability contrasts and result in low overall displacement efficiency.

**Fig. 9** illustrates typical results from an experimental suite of this type. Relative permeability curves in the Case 1 represent the results of an experimental program where interfacial tension effects dominate and are significant in increasing the recovery of oil. It can be seen from this set of incremental relative permeability curves that the reduction in interfacial tension between the two fluid sets causes a significantly lower residual oil saturation to be obtained and much higher overall recovery factor and better sweep efficiency.



**Fig. 9** Relative Permeabilities at Constant Interfacial Tension

Contrasting this effect, relative permeability curves in the Case 2 provide an illustration of a reservoir scenario where the mobility, pore size distribution, and core wettability effects appear to completely dominate. Examination of the relative permeability curves from this test illustrates that there was virtually no difference in relative permeability performance and, in particular, the ultimate recovery of residual oil saturation.

It can be seen that even considerable enrichment of the gas (generating a low or near zero interfacial tension condition) does not appreciably improve recovery of performance. In this case, a lean gas and lower injection pressure would provide comparable recovery factors at considerably less expense.

These factors clearly illustrate the importance of an accurate characterization of the reservoir fluids and coupling the phase behavior and interfacial tension conditions with the flow in porous media considerations to obtain an accurate description of PVT and reservoir rock data for use in compositional simulation.

#### PVT AND ROCK DATA IN COMPOSITIONAL SIMULATION

Most of the commercially available *EOS* compositional simulators and in-house models have been improved significantly in terms of robustness, efficiency, and features. The use of *EOS* compositional simulators should be expected to increase in the future.

Compositional reservoir simulators are built on the basis of mass or molar balances of each component. Such a balance is assumed at any moment during the fluid flow. Because of different phases flow at different velocities in the direction that leads to a decrease in the flow potential of each phase, the equilibrium between phases changes with time. To achieve this new equilibrium, mass transfer of these components between phases needs to take place constantly. An *EOS* is used to solve this equilibrium part of the equations governing the multi-phase and multi-component flow at a given pressure and overall composition. After the solution of the equilibrium equations is reached, the *EOS* provides the number of phases, phase molar and mass densities, phase saturations, and the composition of each phase. Subsequently, phase viscosities and interfacial tension between phases can be determined by use of correlations.

Current simulation practices model the reservoir using one set of relative permeability data per rock region. Once rock regions are assigned they are usually fixed over the life of the simulation. The assumption being made is that capillary numbers are constant for the entire model and residual oil saturations are independent of operating conditions throughout the simulation study. In reality, there are variations in capillary numbers in the reservoir, when well rates and/or well locations change with time and especially during multiple contact miscibility development. Conventional belief is that using an ideal relative permeability curve to correspond to total miscibility and scaling these curves for given conditions is satisfactory and the impact of the errors introduced on recoveries is minimal. This assumption might hold true, for homogeneous media and ideal miscibility conditions only.

In reality, truly homogeneous reservoirs are rare. Different velocities can be seen in certain parts of the reservoir due to the preferential flow paths as governed by heterogeneity in pore size distribution.

These flow paths may have capillary numbers high enough to influence endpoints as well as curvature of the saturation functions. Thus, it is very important, to allocate appropriate saturation functions to these flow regions.

Further, when these flow regions are dynamic, conventional compositional simulation would typically require interruption of the simulation to write restart files to update the rock regions. However, this process becomes cumbersome when there are large numbers of pattern and/or flow rate changes.

To better describe the reservoir performance, the authors propose that two sets of capillary pressure and relative permeability curves measured from multi-contacted fluid pairs as described above, if incorporated in the compositional simulator will substantially improve the predicting capabilities. For the cases that are determined from interfacial tension  $\sigma_{\min} < \sigma < \sigma_{\max}$  the following relationships have shown to give representative values of capillary pressure and relative permeability curve at given pressure and composition during a miscible displacement:

$$Sor = \sigma^* Sor|_{\sigma_{\max}} + (1 - \sigma^*) Sor|_{\sigma_{\min}} \quad (3)$$

$$krg = \sigma^* krg|_{\sigma_{\max}} + (1 - \sigma^*) krg|_{\sigma_{\min}} \quad (4)$$

$$krog = \sigma^* krog|_{\sigma_{\max}} + (1 - \sigma^*) krog|_{\sigma_{\min}} \quad (5)$$

$$Pc = \sigma^* Pc|_{\sigma_{\max}} + (1 - \sigma^*) Pc|_{\sigma_{\min}} \quad (6)$$

$$\text{where } \sigma^* = \frac{\sigma - \sigma_{\min}}{\sigma_{\max} - \sigma_{\min}} \quad (7)$$

The interfacial tension,  $\sigma$  is obtained using the modified Macleod-Sugden correlation, given by

$$\sigma_{go} = \left[ \sum_i P_i \left( x_i \frac{\rho_o}{M_o} - y_i \frac{\rho_g}{M_g} \right) \right]^\theta \quad (8)$$

where  $\sigma$  is in (mN/m) and  $\rho$  is in kg/m<sup>3</sup>.  $P_i$  is the parachor of component  $i$  which can be calculated by using correlations. The exponent  $\theta$  has a value slightly below 4, which was originally proposed by Macleod and Sugden<sup>7</sup>.

Since relative permeability curves are determined in the constant interfacial tension relative permeability portion of the program for both the maximum and minimum interfacial tension conditions that exist in the displacement, these relative permeability curves can be input into the simulator model as the bounding relative permeability curves. An algorithm to adjust the configuration of the original immiscible gas-oil relative permeability curves by coupling with an equation-of-state used in the model to adjust the shape of the relative permeability curves as interfacial tension is reduced in the reservoir needs to be introduced in the compositional simulator. Using a tuning protocol of this type allows for more accurate evaluation and calibration of the compositional reservoir simulation model to predict actual reservoir performance.

## CONCLUSIONS

1. The PVT and Core Laboratory protocol along with EOS characterization and modeling methods for miscible processes under gas injection conditions has been reviewed and discussed.
2. A novel method of incorporating relative permeability data to a compositional simulator in case of miscible and near-miscible displacement during gas injection conditions was presented.
3. This method has been applied to several laboratory scale measurements in various porous media with heterogeneous pore size distribution and permeability realizations, coupled with miscibility development.
4. In compositional simulation techniques, for every rock region there is one set of saturation functions. With these modifications, the simulator has dynamic saturation functions per rock region and allocates appropriate relative permeability curves based on measured laboratory data.
5. The technique proposed can also be used as a tool to identify the reservoir performance at different rock regions.

## ACKNOWLEDGEMENT

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## NOMENCLATURE

$E$	=	Overall displacement efficiency
$E_D$	=	Microscopic displacement efficiency
$E_V$	=	Macroscopic displacement efficiency
$k_{rg}$	=	Gas phase relative permeability
$k_{rog}$	=	Oil phase relative permeability
$M_g$	=	Gas phase molecular weight
$M_o$	=	Oil phase molecular weight
$N_c$	=	Capillary number
$P_c$	=	Capillary pressure
$P_1$	=	Parachor of component $i$
$S_{or}$	=	Residual oil saturation
$u$	=	Darcy's velocity
$x_i$	=	Mole fraction of component $i$ in liquid
$y_i$	=	Mole fraction of component $i$ in gas
$\sigma$	=	Interfacial tension
$\rho_g$	=	Gas phase density
$\rho_o$	=	Oil phase density
$\mu$	=	Phase viscosity
$\sigma^*$	=	Dimensionless IFT
$\theta$	=	Exponent in IFT correlation

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