

Impact of Three-Phase Relative Permeability Model on Recovery in Mixed Media: Miscibility, IFT, and Hysteresis Issues

H. Behzadi and V. Alvarado*

Department of Chemical and Petroleum Engineering, University of Wyoming, 1000 East University Avenue, Laramie, Wyoming 82071

Received June 14, 2010. Revised Manuscript Received August 29, 2010

This paper explores the importance of proper choice of three-phase relative permeability model for mixed-wet media, in contrast with commonly available water-wet rock models, that is, Stone1 and Baker. The mixed-wet condition is likely the most frequently encountered wetting condition worldwide.^{1,2} Two formulations are available under these conditions. Blunt³ developed a model that is somewhat complex to employ in simulators. In contrast, Jerauld^{4–6} formulated a model that is relatively easier to implement. Jerauld's model incorporates the effect of interfacial tension (IFT) between phase pairs, as well as the ability to model mixed wettability. In this paper, to evaluate the effect of three-phase relative formulation, Stone 1 is used as a paradigm of strong wetting and serves as a base comparison for a mixed-wet formulation, namely, Jerauld's model. We illustrate the differences in performance prediction in three-phase oil relative permeability (k_{ro}) for the same two-phase relative permeability data sets. We show how Jerauld's formulation can be used in commercial simulators, though in a limited fashion. Recovery prediction differences as well as the effect of gas miscibility on oil relative permeability to water (k_{row}) are shown. Results show that three-phase k_{ro} values, based on Jerauld's model, can be up to 2 times lower than those predicted by using Stone1 and consequently the calculated recovery using Stone 1 model might be overestimated by 21% at immiscible condition. Gas miscibility affects gas-oil relative permeability and oil–water relative permeability as well. Miscibility diminishes the oil-to-water relative permeability (k_{row}), resulting in lower recovery. The recovery predicted using Stone 1 model is overestimated by 13% at 80% miscibility with respect to Jerauld's model, if the effect of miscibility is only accounted for oil–gas relative permeability. We show the importance of using an adequate three-phase model in mixed-wet system in addition to accounting for the effect of gas miscibility on oil–water relative permeability.

Introduction

Mixed wet is possibly the most frequently encountered condition in reservoirs worldwide. However, the vast majority of experiments has been completed in water-wet and oil-wet rocks.^{7–11} Availability of relative permeability data in mixed-wet media is limited to few data sets. DiCarlo et al.¹² measured relative permeability in mixed-wet sand packs, while Jerauld^{4–6} did extensive studies on Prudhoe Bay cores. It is only recently that proper three-phase relative permeability models for mixed-wet media based on transformation of two-phase relative

permeability curves have become available.¹³ However, as of yet, none of the commercial simulators incorporates mixed-wet relative permeability models, to the best of our knowledge. In this study, we use models available in commercial simulators only. The main question raised here is to what extent we need to use mixed-wet relative permeability models in reservoir simulation. Additionally, we would like to address the question as to how much error arises from application of strong phase-wetting relative permeability models rather than mixed-wet ones. In this work, we use strong water wetness as paradigm of strong wetting, in contrast with mixed-wet conditions.

The most recent models for mixed-wet systems have not been benchmarked for predictive performance. Oliveira compared models for water-wet systems and showed that Stone 1 matched the experimental data significantly better than Baker, Hustad, Delshad, and DiCarlo models. Kjosavik¹⁴ introduced two-phase relative permeability for mixed-wet rock based on Corey–Burdine model; he did not extend his work to three-phase relative permeability. Blunt³ established a three-phase model based on saturation-weighted interpolation between the two-phase permeability curves. This model accounts for wettability, trapping, and layer drainage. Blunt's model assumes that the same amount of gas is trapped by water and oil for a specific capillary number, which is valid for a strong

*To whom correspondence should be addressed. E-mail: valvarad@uwyo.edu.

(1) Kovscek, A. R.; Wong, H.; Radke, C. J. *AIChE J.* **1993**, *39*, 1072–1085.

(2) Robin, M.; Rosenberg, E.; Fassi-Fihri, O. *SPE Form. Eval.* **1995**, *10*, 11–19.

(3) Blunt, M. J. *SPE J.* **2000**, *5*, 435–445.

(4) Jerauld, G. R. *SPE Reservoir Eng.* **1997**, *12*, 255–263.

(5) Jerauld, G. R. *SPE Reservoir Eng.* **1997**, *12*, 66–73.

(6) Jerauld, G. R.; Rathmell, J. J. *SPE Reservoir Eng.* **1997**, *12*, 58–65.

(7) Donaldson, E. C.; Dean, G. W. *Rep. Invest.* **6826**, **1966**.

(8) Sahni, A.; Guzman, R.; Blunt, M. SPE Technical Paper 36664, Denver, CO, 1996.

(9) Maini, B.; Nicola, F.; Goldman, J.; Sarma, H. Petroleum Recovery Institute, Calgary, Canada, 1990.

(10) Oak, M. J.; Baker, L. E.; Thomas, D. C. *J. Pet. Technol.* **1990**, *42*, 1054–1061.

(11) Oak, M. SPE Technical Paper 22599, Dallas, Texas, 1991.

(12) DiCarlo, D. A.; Sahni, A.; Blunt, M. J. *SPE J.* **2000**, *5*, 82–91.

(13) Pejic, D.; Maini, B. SPE Technical Paper 81021, Port-of-Spain, Trinidad and Tobago, 2003.

(14) Kjosavik, A.; Ringen, J. K.; Skjaeveland, S. M. *SPE J.* **2002**, *7*, 49–58.

wetting condition, thus requiring extensions of the model to other than water-wetness.³ Also, the choice of oil saturation when layer drainage starts is arbitrary, that is, a free matching parameter needs to be adjusted. Jerauld⁴ developed two- and three-phase relative permeability models. These are the only models verified through comparison with coreflooding data that we are aware of. Unlike Blunt's model, Jerauld's model requires none of the extensions or matching parameters.

The second important issue that has not been addressed in earlier publications is the effect of miscibility on all pairs of relative permeability curves, and consequently recovery. There are two main three-phase models that incorporate interfacial tension (IFT) parameters between phases: Blunt's³ and Jerauld's.⁴ Both models consider the effect of miscibility on all phase-pairs. For instance, when the injected gas is partially/completely miscible in oil then the two-phase oil-gas relative permeability, $k_{ro,g}$, oil relative permeability with respect to gas, and $k_{r,g,o}$, gas relative permeability with respect to oil, will change. However, since oil composition changes, the oil–water relative permeability is subject to change. Thus, the legitimate question here is how much error might arise if miscibility effects on the third phase are ignored. It should be noticed that Todd–Longstaff model in black oil simulation cannot address this issue. Hustad's model is available in at least a commercial compositional simulator at present. The model allows for linear relative permeability interpolation based on a normalized IFT. However, Hustad's model has not been compared with mix-wet rock experimental data. Blunt³ and Jerauld⁴ claim that their models can consider IFT alteration. In terms of implementing a mixed-wet rock relative permeability model, we use Jerauld's model through an extension of available Stone 1 formulations in simulators.

We explore both questions, proper choice of three-phase relative permeability, that is, on the basis of system wettability and gas miscibility effects on k_{row} , oil relative permeability with respect to water, and find that both issues are important and require attention when dealing with mixed-wet and miscible systems. Moreover, since hysteresis has increasingly become a more important concept, especially for coupled CO₂-EOR/Storage purposes, we investigate hysteresis effect on mixed wet system as well. In the following section, we present step-by-step method to address the questions formulated here.

The objectives of this paper are, first, to show the importance of using adequate three-phase relative permeability for mixed-wet systems and, second, miscibility effects on third phase relative permeability. The paper is organized as follows. After the introduction, the model formulation is described in the Theory and Method section. In that section, the base algorithm for implementing Jerauld's model in a commercial simulator is described. Results and discussions follow. Limitations are presented on Consideration on Jerauld's Model Implementation section. Conclusions are provided at the end. An Appendix contains additional results on error analysis to avoid clouding the discussion in the main body of the article.

Theory and Method

Jerauld^{4–6} introduced a model to calculate three-phase relative permeability data for Prudhoe Bay, a mixed-wet sandstone formation, from two-phase relative permeability curves. Jerauld's model is unique in that it includes dependence of relative permeability on composition and consequently on oil–gas interfacial tension in addition to the hysteresis in oil, gas, and water curves.

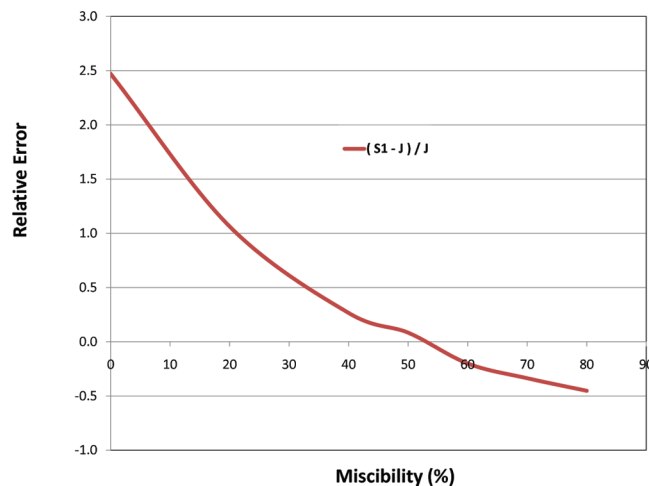


Figure 1. Relative error of Stone 1 with respect to Jerauld's relative permeability is plotted versus miscibility. $S_g = 0.05$.

First, we evaluated the overall difference between Stone 1 and Jerauld's model, calculated as follows:

$$\text{relative error} = \frac{\int \int (k_{ro}^{\text{Stone1}} - k_{ro}^{\text{Jerauld}}) dS_g dS_w}{\int \int k_{ro}^{\text{Jerauld}} dS_g dS_w} \quad (1)$$

The relative error corresponds to the ratio of the integral difference between the calculated three-phase relative permeability value based on Stone 1 and Jerauld, over the integral of Jerauld's k_{ro} , eq 1. Residual saturation of phases dictates the integral domain (for more details about derivation of Jerauld's model see ref 4). Figure 1 shows the relative error between Stone 1 and Jerauld models, plotted versus miscibility, where gas saturation is at residual value, $S_g = 0.05$ (we call it Stone 1's relative error). Stone 1 gives higher relative permeability value than Jerauld for an immiscible situation and the difference becomes smaller at higher miscibility. At high miscibility, Jerauld's oil relative permeability is larger than Stone 1, that is, above 55% miscibility (Figure 1).

Phase displacement stability is function of mobility ratio (M), defined here as

$$\text{mobility ratio} = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o}} \quad (2)$$

If $M \leq 1$, fluid displacement is stable, while it becomes unstable for $M > 1$, leading to viscous fingering. Stone 1 model yields higher relative permeability values than Jerauld's for an immiscible situation, with the difference becoming smaller. Therefore, it is expected that breakthrough will happen later, if Stone 1 model is used for immiscible situations. This means that the estimated recovery would be optimistic when fluids are immiscible, if Stone 1 model is employed for a mixed-wet reservoir. In the next section, we will show how Jerauld's model can be implemented through available Stone 1 model in commercial simulators. This helps us to understand how the predicted recovery might quantitatively be influenced by the choice of three-phase relative permeability model.

Jerauld's Model through Stone 1. In terms of formulation, Jerauld's oil phase relative permeability can be reduced to Stone 1, if k_{roo} equals S_o .⁴ In fact, this is no more than an extension of Stone 1,⁴ which enables one to recast it as Stone

1 for implementation in commercial simulators. We show the k_{ro} difference between these two models as function of gas and water saturation, and then this difference is translated into recovery. The same two-phase relative permeability data sets are used to produce three-phase relative permeability data based on Jerauld and Stone 1. Prudhoe Bay two phase relative permeability data sets are employed and can be found in Jerauld's article.⁴ In addition, Jerauld constant parameters are provided in Table 1.

Jerauld's three-phase relative permeability model implementation goes as follows

$$k_{ro}^{\text{Jerauld}} = k_{roo} \frac{k_{rog}(1 - S_g) \times k_{rhw}(1 - S_w)}{k_{roo}(1 - S_g) \times k_{roo}(1 - S_w)} \quad (3)$$

$$k_{rgg}(S_g) = \frac{(1 + \theta c_{g2}) S_{gg}^{\theta c_{g1} + (1 - \theta)}}{1 + \theta c_{g2} S_{gg}^{\theta c_{g3}}} \quad (4)$$

$$k_{rwh} = \frac{(1 + c_{wh5}) \left[\frac{S_w - S_{wrh}^*}{1 - S_{wrh}^*} \right]^{c_{wh4}}}{1 + c_{wh5} \left[\frac{S_w - S_{wrh}^*}{1 - S_{wrh}^*} \right]^{c_{wh4}}} \quad (5)$$

while k_{ro} based on Stone 1 model is

$$k_{ro}^{\text{Stone1}} = S_{oe} \frac{k_{rog}(1 - S_g) \times k_{row}(1 - S_w)}{k_{row}^{\text{end}} \times (1 - S_{ge})(1 - S_{we})} \quad (6)$$

Now, we equate eqs 3 and 6 to calculate k_{row} in mixed wet system by using available Stone 1 formulation in simulators.

$$k_{row}(1 - S_w) = \frac{k_{row}^{\text{end}} \times (1 - S_{ge})(1 - S_{we})}{S_{oe}} \times k_{roo}(S_o) \frac{k_{rhw}(1 - S_w)}{k_{roo}(1 - S_g) \times k_{roo}(1 - S_w)} \quad (7)$$

$$k_{rog}(1 - S_g) = \left(\frac{1 - S_g - \theta S_{org}}{1 - \theta S_{org}} \right)^{\theta c_{og1} + (1 - \theta)} \quad (8)$$

$$k_{roo}(S) = \left(\frac{S - \theta S_{ot}}{1 - \theta S_{ot}} \right)^{\theta c_{o1} + (1 - \theta)} \quad (9)$$

At this point, the adapted Jerauld's relative permeability can be calculated through eq 7, which enables us to implement Jerauld's k_{row} in simulators. Notice that k_{row} in addition to normal dependence to S_w , is a function of gas saturation because of adaptation. However, we can only employ one k_{row} set, which means in practice one single S_g value (denoted here as S_{gco}) for estimating the adapted k_{row} to mimic Jerauld's three-phase model, in a Stone-like fashion. Therefore, we are forced to implement Jerauld's model in an incomplete way because of limitations of available relative permeability formulations in reservoir simulators. This incomplete representation of Jerauld's model is labeled adapted Jerauld. The calculated adapted-Jerauld k_{ro} is 96% more than Jerauld value, in average, because of using single S_{gco} value ($S_{gco} = 0.05$). However, relative error is cut 1.5 times by using adapted Jerauld rather than Stone 1 for immiscible situations. In other words, the predicted three-phase

oil relative permeability by Stone 1 is 250% more than that of Jerauld's.

Note: Keep in mind that the adapted-Jerauld model is not new. It is only the representation of Jerauld's model in commercial simulators that we use to quantitatively assess the recovery difference in mixed wet reservoir, if Stone 1's three-phase relative permeability model is employed rather than Jerauld's.

Gas Miscibility Effect on k_{row} . When gas dissolves in oil, it changes k_{rgo} and k_{rog} . Perhaps, more importantly in the context of this work is the alteration of k_{row} . Jerauld⁴ incorporates this effect in his three-phase model. Comparison of the k_{rgw} and k_{row} equations show that they can be combined into a single,⁴ hydrocarbon hysteresis model with respect to miscibility to yield:

$$k_{rhw} = \frac{(1 - c_{hw2}) S_1^{c_{hw4}} S_2^{c_{hw1}}}{1 + c_{hw2} S_1^{c_{hw6}} S_2^{c_{hw3}}} \quad (10)$$

where

$$S_1 = \frac{S_{hw}^{\text{max}} - S_{htw}(S_{hw}^{\text{max}})}{1 - S_{hrw}} \quad (11)$$

$$S_2 = \frac{1 - S_w - S_{htw}(S_{hw}^{\text{max}})}{S_{hw}^{\text{max}} - S_{htw}(S_{hw}^{\text{max}})} \quad (12)$$

and

$$S_{htw} = \frac{S_{hw}^{\text{max}}}{1 + \left(\frac{1}{S_{hrw}} - 1 \right) \times (S_{hw}^{\text{max}})^{1/(1 - S_{hrw})}} \quad (13)$$

where the maximum hydrocarbon saturation is calculated from the following equation (see ref 4 for more details).

$$S_{hw}^{\text{max}} = \max\{1 - S_w, S_g^{\text{max}} + f_h(1 - S_w^{\text{min}} - S_g^{\text{max}})\} \quad (14)$$

$$S_{hrw} = (1 - f_h) S_{gr} + S_{orw} \quad (15)$$

$$c_{hw1} = (1 - f_h) c_{g1} + f_h c_{ow1} \quad (16)$$

$$c_{hw2} = (1 - f_h) c_{g2} + f_h c_{ow2} \quad (17)$$

$$c_{hw3} = (1 - f_h) c_{g1} \left(1 + \frac{1}{c_{g2}} \right) \quad (18)$$

$$c_{hw4} = (1 - f_h) c_{g1} + f_h c_{ow4} \quad (19)$$

$$c_{hw6} = (1 - f_h) c_{g1} \left(1 + \frac{1}{c_{g2}} \right) + f_h c_{ow6} \quad (20)$$

The value of F_h is calculated based on Parachor-weighted molar density change as a measure of composition alteration. This parameter can be calculated compositionally. Ayirala and Rao¹⁵ offered a new mechanistic Parachor model to predict dynamic interfacial tension and miscibility in complex hydrocarbon system where traditional Parachor model is not as accurate in predicting IFT applicable for

(15) Ayirala, S. C.; Rao, D. N. *J. Colloid Interface Sci.* **2006**, *299*, 321–331.

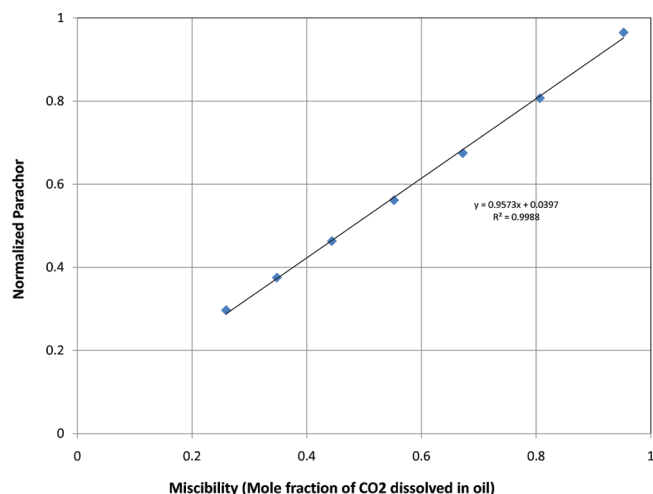


Figure 2. Normalized Parachor-weighted molar density versus miscibility factor of CO₂ in oil.

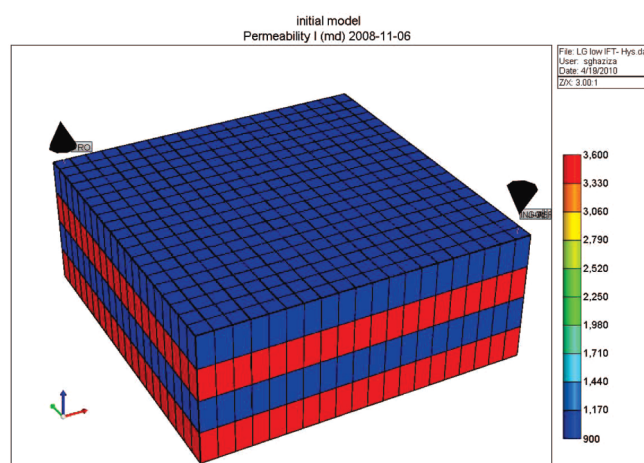


Figure 3. Three-dimensional conceptual model.

mass transfer between multicomponents phases. However we do not need this complex procedure since we already calculated IFT and we are interested in using pseudo components. Here all components are lumped into one pseudo component and then IFT and density of this pseudo-component is calculated based on the Peng–Robinson equation of state. Parachor parameter is estimated by Macleod¹⁶ and Sugden¹⁷ method, eq 21. The Parachor parameter is a function of IFT and molar density difference of vapor and liquid phases based on this equation.

$$P = \frac{\sigma^{0.25}}{\rho_m^l - \rho_m^v} \quad (21)$$

F_h , the normalized Parachor-weighted molar density, and miscibility are calculated and plotted versus one another in Figure 2.

S_{hrw} and k_{hrw} change with respect to how oil becomes gas-like. Therefore hydrocarbon–water relative permeability can be adjusted with respect to miscibility (eq 10).

Table 1. Parameter Used in Constructing Relative Permeability Data

parameter	value ^a
c_{g1}	3.2
c_{g2}	6.5
c_{g3}	3.5
c_{o1}	6
c_{og1}	6.7
c_{ow1}	1.6
c_{ow2}	1.2
c_{ow4}	6
c_{ow6}	1.5
c_{wh4}	2.5
c_{wh5}	1
S_{gc}	0.05
S_{or}	0.19
S_{wmin}	0.3

^a Residual, connate, and minimum are equal except where mentioned.

Conceptual Model. The numerical model in this work uses data from the Mangala field in Barmer basin in India.^{18–21} The sector model is extended to 1000 ft in the horizontal directions, while the thickness is 134 ft, for the Upper Fatehgarh unit (see Figure 3). This portion of the formation is formed by sinuous, meandering, fluvial channel sands. Two repeated shaly sand and sand layers with average permeability of 3600 and 900 millidarcy (md) for horizontal direction are used, while in the Z direction the value is 10% of the horizontal one. The average porosity, formation pressure and reservoir temperature are 0.26, 2000 psi, and 165 °F, respectively.

The injection procedure is as follows: Initially, 1.2 pore volumes (PV) of water are injected, followed by 0.25 PV of gas, which is then chased with 2.1 PV of water. The injection rate is 8000 bbl/day for water, while the gas rate is 1/4 of the water rate at reservoir conditions. The whole reservoir thickness is perforated.

Results and Discussion

We cover three main aspects here. First, the relative permeability in Jerauld's model is compared with Stone 1 model. Then, the effect of miscibility on oil–water relative permeability is investigated. Third, the effect of hysteresis is studied and compared to that of wettability.

Comparison of Three-Phase Relative Permeability. Several aspects of rock–fluid interactions in mixed-wet systems have been assessed. Results reveal that proper choice of three-phase relative permeability model is quite important: more than 21% error in recovery found if an inadequate three-phase relative permeability model is used at immiscible situation; however, Stone 1's and adapted-Jerauld's relative error are 250% and 96%, respectively, Figure 4. Figure 5 shows the absolute difference in k_{ro} between two three-phase models using Jerauld and Stone 1. There is a significant difference at S_{gr} , and as expected gas saturation has a more pronounced effect on k_{ro} . It appears that S_{gco} equal to S_{gr} is a good choice (see Appendix for details).

The difference between these two three-phase relative permeability models might have a significant influence on recovery. We compared the recovery in a sector model. We

(16) Macleod, D. B. *Trans. Faraday Soc.* **1923**, *19*, 38–41.

(17) Sugden, S. J. *Chem. Soc.* **1924**, *125*, 1177–1189.

(18) Pandey, A.; Kumar, M.; Beliveau, D.; Corbishley, D. SPE Technical Paper 113347, Tulsa, OK, 2008.

(19) Pandey, A.; Beliveau, D.; Corbishley, D.; Kumar, M. SPE Technical Paper 113131, Mumbai, India, 2008.

(20) Osullivan, T.; Beliveau, D.; Kumar, H. SPE Technical Paper 113163, Mumbai, India, 2008.

(21) Osullivan, T.; Beliveau, D.; Kumar, H. SPE Technical Paper 113164, Mumbai, India, 2008.

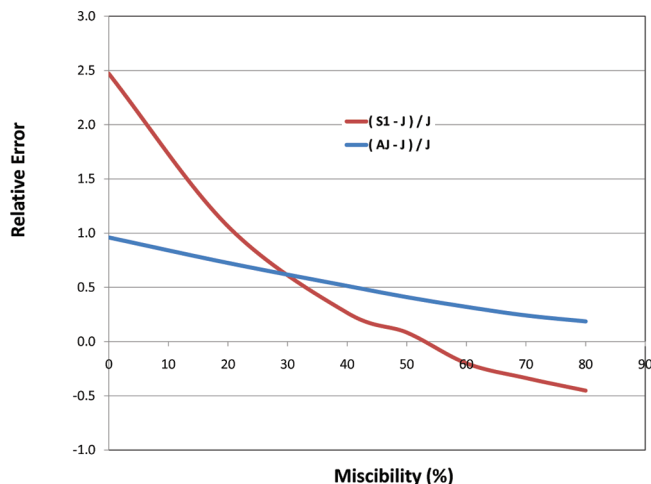


Figure 4. Comparison of relative error of adapted-Jerauld and Stone 1 versus miscibility. $S_{gco} = 0.05$.

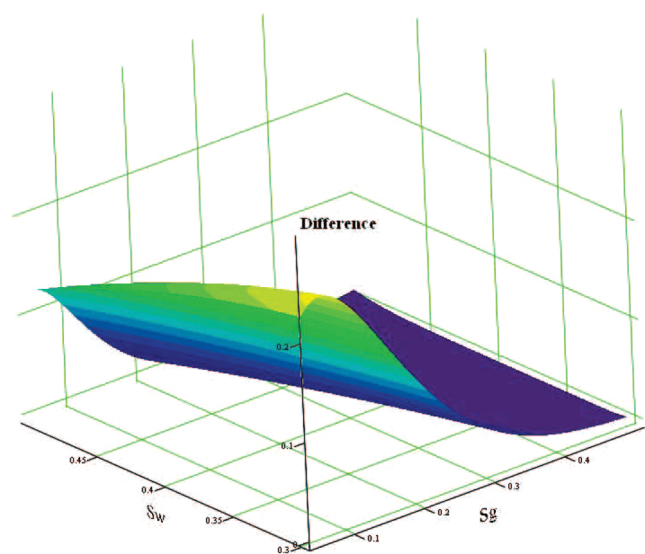


Figure 5. Absolute oil relative permeability difference between Jerauld and Stone 1 models.

used a conceptual model based on Managala field published data and k_{ro} (three-phase) is calculated using these two different models to show how Stone 1 model overestimates recovery at immiscible situation. The recovery is plotted for a wide range of miscibility, Figure 6.

The relative error of Stone 1 is 250%, while it is 100% for adapted Jerauld and the recovery difference between Stone 1 and Adapted Jerauld is 21%. If we assume a linear relationship between relative error and recovery difference, then, we might estimate the recovery difference between a simulation employing Stone 1's model rather than Jerauld's model. This difference would be 35% ($21\% \div (250\% - 100\%) \times 250\%$).

Miscibility Effect on Oil–Water Relative Permeability. Gas miscibility effects on k_{row} , which are not generally properly addressed in typical simulations, reflect appreciably in terms of recovery. Gas miscibility changes fluid properties and relative permeability. Compositional simulation can properly track the fluid property change, but there is no straightforward solution for relative permeability alteration. Todd and Longstaff's scheme, that is, black oil approximation to emulate compositional simulation, might address oil-gas

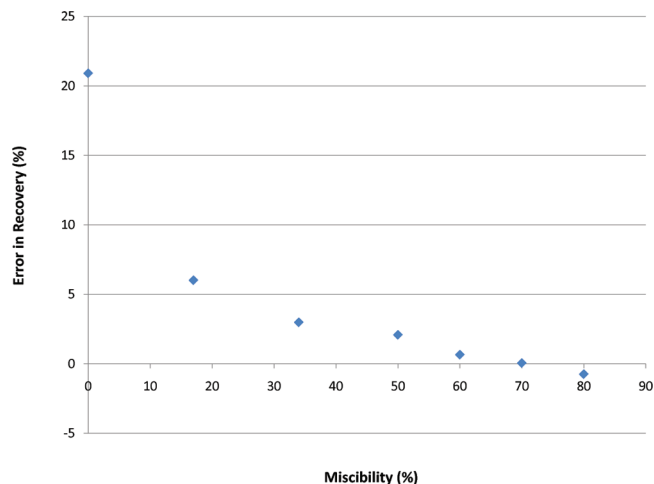


Figure 6. Comparison of Jerauld three-phase model with Stone 1 for a wide range of miscibility. $S_{gco} = 0.05$.

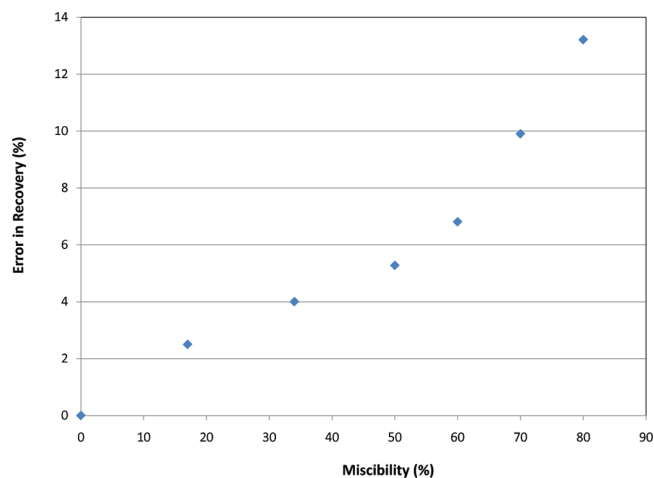


Figure 7. Error in recovery as a result of gas miscibility effect on k_{row} . $S_{gco} = 0.05$.

relative permeability alteration based on a miscibility factor, but it does not provide a way to deal with how oil–water relative permeability might change. Blunt's and Jerauld's three-phase relative permeability models could address this issue.

We employed Jerauld's model to consider the miscibility effects on all phase relative permeability pairs, $k_{rog} - k_{rgo}$ and $k_{row} - k_{rwo}$. This model enables one to track third phase relative permeability alteration, k_{row} , which is not typically pondered because of lack of IFT parametrization in relative permeability models.

Although gas miscibility might lower oil viscosity, it could at the same time reduce the oil–water relative permeability to yield a sooner breakthrough and lower recovery. Therefore recovery might be overestimated if gas miscibility effects on oil viscosity and oil–gas relative permeability are solely considered. Figure 7 shows how gas miscibility effects on k_{row} might reduce recovery under perfect mixing conditions.

The effect of miscibility on all phases can also be simulated by Hustad method.^{22,23} Since this model is incorporated in a

(22) Hustad, O. *SPE J.* **2002**, *7*, 59–69.

(23) Hustad, O.; Browning, D. SPE Technical Paper 125429, Abu Dhabi, UAE, 2009.

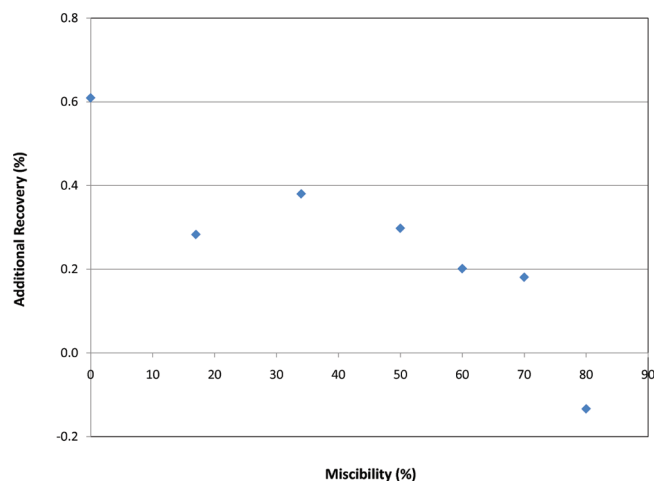


Figure 8. Hysteresis effect on recovery for different IFT system. $S_{\text{gco}} = 0.05$.

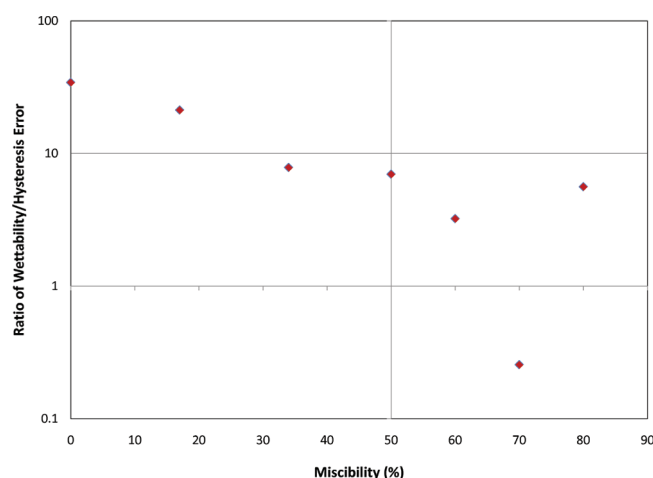


Figure 9. Error in recovery resulting from improper representation of wettability divided by hysteresis effect on recovery are plotted versus miscibility. $S_{\text{gco}} = 0.05$.

commercial simulator, consequently miscibility can be estimated in each grid block. Thus, it does not require our assumption, that is, a homogeneous miscibility condition. However, the linear interpolation of relative permeability between immiscible and perfect miscibility based on normalized IFT, Hustad model, was not proven. In addition, Hustad's relative permeability model, which is referred as to ODD3P in the ECLIPSE simulator, did not show good match with experimental data (Figure 3 in Oliveira and Demond's article²⁴).

Hysteresis in Mixed-Wet Reservoir. Figure 8 shows effects of hysteresis on recovery for a whole range of miscibility in a mixed-wet system. Although hysteresis has an appreciable effect on recovery in water-wet systems (not shown here), this effect is less important when the system wettability shifts toward intermediate- and mixed-wettability. One important implication of these results is the possible overprediction of storage in CO₂-EOR/Storage projects because of the trapping by hysteresis associated with strong wetting, as no commercial simulator, to the best

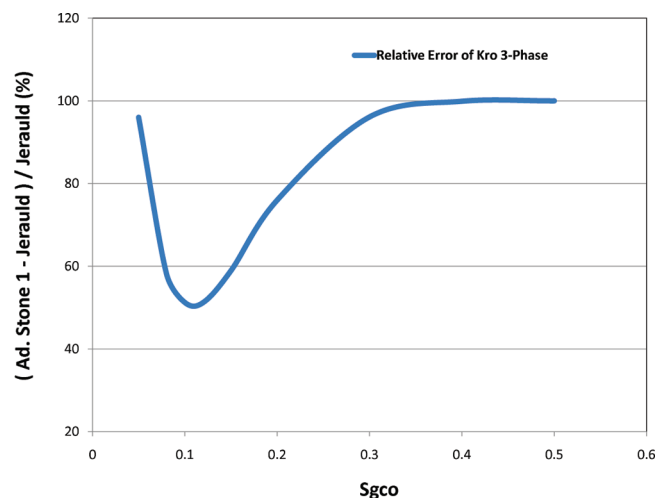


Figure 10. Relative error between adapted Jerauld and Jerauld models with respect to S_{gco} .

of our knowledge, contains an adequate mixed-wet relative permeability model. Moreover, CO₂-brine contact angles measured at high pressure reflect a drop in water wetness.^{25,26}

Wettability versus Hysteresis. In this section, the error in recovery associated with using inadequate three-phase relative permeability models is compared with the error because of neglecting hysteresis. The former error comes from results given in eq 7, and the latter error from results presented in Figure 9. To compare contributions of wettability (proper choice of relative permeability) and hysteresis, we calculate the ratio of these two errors, that related to improper choice of three-phase relative permeability model divided by the error from not considering hysteresis. If this ratio is more than one, wettability has more effect on recovery than hysteresis and vice versa. Wettability versus hysteresis reaches the maximum value, under immiscible conditions, 34 times more, while by increasing miscibility this ratio reduces to less than one at 70% miscibility. However, recovery error of improper choice of relative permeability is not reliable at miscible situation.

Considerations on Jerauld's Model Implementation

We calculate the relative error of this methodology, based on the difference between adapted Jerauld model, using eq 7, and Jerauld's relative permeability model, using eq 1, but $k_{\text{ro}}^{\text{Stone1}}$ is substituted with $k_{\text{ro}}^{\text{AdaptedJerauld}}$. This relative error is plotted in Figure 4 along with Stone 1's relative error. One issue in calculating the relative error is the optimum S_{gco} value. The adapted Jerauld relative error is plotted versus S_{gco} in Figure 10. The relative error is calculated for whole range of gas–water saturation without any weighting factor. The minimum relative error occurs at $S_{\text{gco}} = 0.1$. However, this does not affect the recovery in the same way. The minimum recovery difference between adapted Jerauld (representation of Jerauld in commercial simulators) and Stone 1 happens at $S_{\text{gco}} = 0.05$, residual gas saturation. This is so because k_{ro} is higher at residual gas saturation. Therefore, suppressing the maximum difference of k_{ro} , happening at residual saturation,

(25) Chiquet, P.; Broseta, D.; Thibeau, S. *Geofluids* **2007**, 7, 112–122.

(26) Yang, D.; Y., G.; Tontiwachwuthikul, P. *Energy Fuels* **2008**, 22, 2362–2371.

(24) Oliveira, L.; Demond, A. *Contam. Hydrol.* **2003**, 66, 261–285.

is suspected to be the reason why error in recovery is minimum if S_{gco} equates S_{gr} . The difference between these two models for different S_{gco} is shown in Appendix. However, there is still an error in range of 50–100%.

The second limitation of our implementation is that we cannot draw strong conclusion for miscible situations, since the representation of Jerauld's model in commercial simulators is not good enough for this purpose at miscible conditions, as the available models in simulators does not allow us to accommodate a full implementation of the mixed-wet model. It should be noticed that adapting of commercial simulators at higher miscibility may not properly represent Jerauld's model (Figure 4). The relative error of Stone 1 is less than adapted Jerauld around 50% miscibility.

The effect of miscibility on third phase has also a simulation limitation. Here, miscibility is assumed to be the same for the whole model, that is, perfect mixing condition. However, in reality, miscibility is not homogeneous and therefore various miscibility conditions can exist in the simulation model (and the reservoir for that matter). In other words, we need compositional functionality of relative permeability in numerical simulators for all pairs.

Despite the aforementioned pitfalls, this algorithm reduces relative error from 250% to the range of 100–50% as shown in Figure 10 (immiscible situation). This study brings up the importance of using adequate three-phase relative permeability model to light. Therefore, if a mixed-wet reservoir encounters three-phase flow situations, such as water flooding below bubble point or water alternating gas (WAG), the economical assessment would be optimistic if water-wet relative permeability model is used (see Figure 6). Also, miscibility effect on third phase can cause lower predicted recovery. Thus, miscible flooding, for example, CO_2 high-pressure injection, might not be as promising as one expects from simulations performed using water-wet models.

Conclusions

We show that significant overestimation of recovery can be obtained if Stone 1's model is employed rather than Jerauld's for mixed-wet systems. At least 21% recovery error might occur (35% error if a linear relationship is used). Also, the change in oil–water relative permeability due to gas miscibility in oil yields substantial overestimation of recovery, up to 13%. Moreover, analysis of hysteresis in mixed-wet systems for a wide range of IFT systems reveals, on one hand, that it has smaller effects on recovery in comparison with water-wet systems. However, it does have much less effect than wettability, on the other hand. The results here indicate that CO_2 -EOR/Storage projects might overestimate CO_2 trapping by hysteresis, which produces unrealistic CO_2 storage.

The conclusions derived from comparing one traditional water-wet model, Stone 1, and one mixed-wet rock model for relative permeability, Jerauld's, are likely to hold in terms of relative differences on the basis of ours and other published works. Hence, high risk of significantly wrongly estimating recovery demands careful choice of relative permeability model for three-phase flow conditions in mixed-wet systems. More work is needed to produce adequate models for mixed-wet reservoirs in simulators.

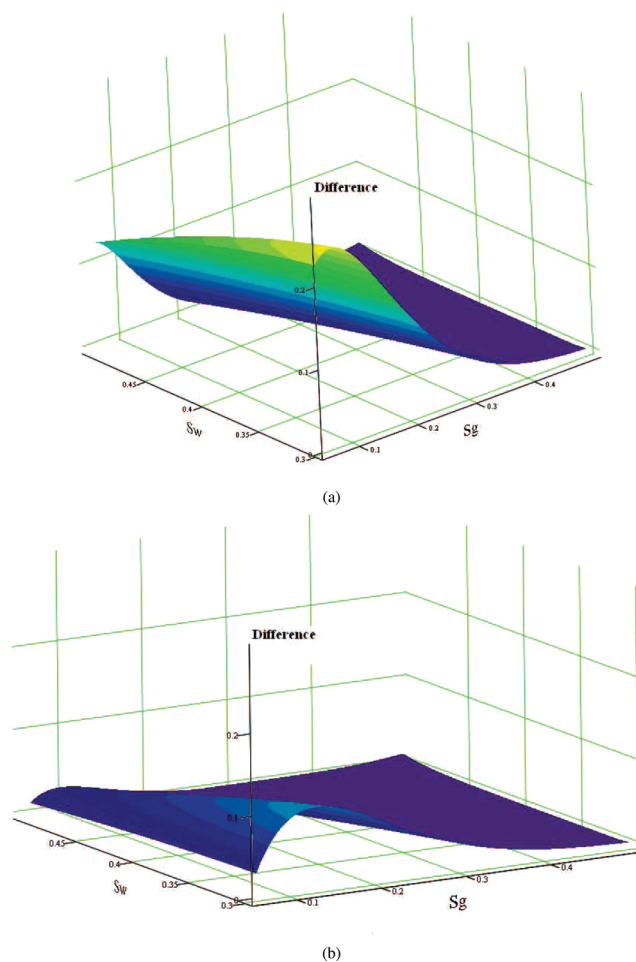


Figure 11. Comparison of absolute oil relative permeability difference between Jerauld and Stone I models before (a) and after (b) adaptation. $S_{\text{gco}} = 0.05$.

Acknowledgment. We would like to acknowledge CMG Ltd. for providing research licenses of their software suite. We would like to acknowledge the Enhanced Oil Recovery Institute at the University of Wyoming for financial assistance.

Appendix

There are two main criteria for choosing S_{gco} , which are relative error and maximum error (maximum error happens at residual saturation, S_{gr}). The relative error between Stone 1 and Jerauld models is 250% before adaptation. This error can be reduced if we adapt Stone 1 model to mixed wet system by using eq 7. It is suspected that the maximum error renders more numerical error on recovery. There is a trade-off in choosing S_{gco} . For instance, if we pick the residual gas saturation, then the maximum error in relative permeability prediction is low, while the relative error is not minimal, 96% (see Figure 10), while the difference in recovery between a sector model using Stone 1 and Jerauld models is 21% (Figure 6). However, at S_{gco} equals 0.1, the relative error would be ~50% less than the corresponding value at $S_{\text{gco}} = 0.05$, but the difference in recovery is 41%. The difference in recovery becomes much larger, that is, 118% at $S_{\text{gco}} = 0.22$. Therefore, we speculate that the high error at low gas saturation arises, where k_{ro} is high and consequently its contribution to recovery is significant, shall be used as main criterion for S_{gco} selection. Therefore, we selected $S_{\text{gco}} = 0.05$ in our

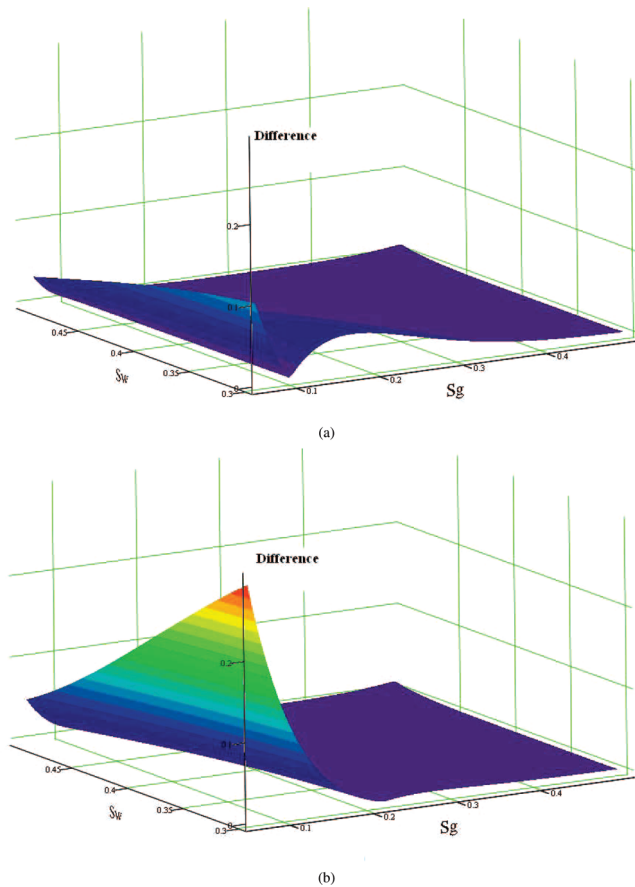


Figure 12. Comparison of absolute oil relative permeability difference between Jerauld and adapted Stone I for $S_{gco} = 0.1$ (a) and 0.22 (b).

study. This selection yields a smaller difference between Jerauld and Stone 1 models, more optimistic results. In other words, we would encounter more error if a higher S_{gco} is picked. Relative error before and after adaptation is compared in Figure 11. Also, the absolute oil relative permeability difference between models for S_{gco} equals 0.1

and 0.22, as shown in Figure 12. It looks like $S_{gco} = 0.22$ is not a proper choice.

Nomenclature

- c_{ijk} = k th parameter in i -phase/ j -phase relative permeability
- c_{ik} = k th parameter in i -phase relative permeability (two-phase fitting parameters)
- f = function representing composition dependence
- k_{ro}^X = three phase oil relative permeability based on model X, that is, Jerauld or Stone 1.
- k_{rocw} = relative permeability to oil at initial water saturation
- k_{ri} = relative permeability for i phase
- k_{rij} = relative permeability of i phase with relation to j phase
- k_{rw}^{PD} = water relative permeability in primary drainage process
- P = Parachor weighted molar density
- S_i = saturation of i phase
- S_{ie} = effective saturation of i -phase (see ref 16 for equations)
- S_{gc} = critical gas saturation
- S_{gco} = gas saturation used for calculation of adapted k_{row}
- S_{gt} = trapped gas saturation
- S_{irj} = maximum residual of phase i with relation to phase j
- S_{itj} = trapped phase i saturation with respect to phase j
- S_{ot} = trapped oil saturation
- S_w^{\min} = minimum water saturation
- θ = function describing N_c dependence
- σ = IFT

Subscripts

- e = effective
- g = gas
- h = hydrocarbon
- o = oil
- w = water