

# New Method of Incorporating Immobile and Nonvaporizing Residual Oil Saturation into Compositional Reservoir Simulation of Gasflooding

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## Summary

In compositional simulation of gas-injection processes, it is often observed that gridblock oil saturations decrease far beyond the user-defined residual oil saturation, even under immiscible conditions. This numerical phenomenon occurs because oil components are allowed to vaporize into the gas phase as much as the phase equilibrium obtained with an equation of state (EOS) permits. Especially in the vicinity of gas injectors, an oil saturation of zero is sometimes predicted. On the other hand, such significant low oil saturation is rarely seen in laboratory data such as coreflood experiments and slimtube tests.

The reason for the discrepancy between the simulation results and the laboratory results described above is that bypassed oil located in dead-end pores or caused by subgrid-scale heterogeneities is not considered in the current compositional-simulation practice. To overcome this, we developed an innovative method of incorporating laboratory-based residual oil saturations. The proposed method can restrict the excessive vaporization and maintain the prescribed residual oil by accommodating a novel application of the transport coefficient (Barker and Fayers 1994).

## Introduction

Incorporation of the “true” residual oil saturation into the gasflood compositional simulation has been a critical problem in the industry. On the other hand, most compositional simulators allow oil saturations to be as low as an EOS predicts, but no rigorous method has been proposed to honor laboratory observations usually indicating nonzero residual oil saturations. This is why immiscible gas injection is predicted to achieve a good recovery factor despite the fact that even miscible coreflood experiment results rarely show 100% recovery.

Not only laboratory experiments but also field observations indicate that bypassed oil occurs even after the miscible injectant passes through above the minimum miscibility pressure (MMP), as stated by Stalkup (1983) and McGuire et al. (1995). Dead-end pore volume and precipitation can cause such bypassed oil under gas injection with no prior waterflood history. Although the mass transfer in microscopic scale like molecular diffusion can partially recover such bypassed oil, as described by Burger et al. (1996), there still remains the oil behind the miscible front.

For this reason, even under the miscible-flooding condition, the residual oil saturation will not reach 0% in the real heterogeneous reservoir. This residual oil is referred to as miscible flood residual oil saturation (Spence and Watkins 1980). In the conventional compositional simulation, there is no facility to actively define “true” residual oil (nonvaporizing oil) and, hence, the excessive vaporization of oil components into the gas phase is predicted.

Consequently, the miscible flood residual oil saturation could not be represented in the simulation model. This frequently has caused optimistic results in which all the oil in the gridblock can be stripped by the injected gas.

The first attempt to restrict the excessive vaporization described above was made by Fayers et al. (1992), who proposed the concept of dual-zone mixing. In this concept, the phase equilibrium is established between the hydrocarbon trapped in dead-end space (uncontacted oil) and that in the permeable portion of a simulation block. Analogous to a dual-porosity model, uncontacted oil is allowed to disperse only when it is vaporized into the contacted oil or gas. The concept of the transport coefficient (Barker and Fayers 1994) was adopted to incorporate the component dependence in mass transfer. However, the work of Fayers et al. (1992) has not been used widely, primarily because of the complexity of the theory and, hence, special coding was required to accommodate the dual-zone mixing.

In a coreflood simulation, considering and modeling the heterogeneity inside the core sample could yield a residual oil saturation along with the laboratory experiments. However, it is difficult to convey such insight derived from the core-scale heterogeneity to a simulation block size. Besides, it is widely known that pseudofunctions or upscaled relative permeability, especially for gas/oil two-phase flow, do not always work well because the resultant large-scale saturation functions are extremely limited to the assumed pressure and velocity conditions.

In this paper, we present a simple and robust method of incorporating nonvaporizing residual oil saturations, in which the laboratory-based residual oil saturations can be respected exactly. The results of the case studies are also shown where the sensitivity of the residual oil saturations will be discussed.

## Explanation of the Developed Method

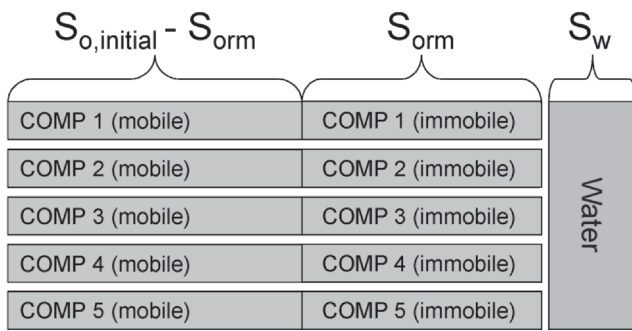
**Overview.** This method consists of three elements: the partitioning of the fluid-component system, an innovative application of the transport coefficient, and relative permeability modification caused by the inclusion of the transport coefficient. We partition the fluid system so that each component has a mobile portion and an immobile portion. This is controlled by assigning different transport coefficients (alpha factors) to each of the mobile and immobile portions as described later.

**Partitioning of the Fluid-Component System.** In the real reservoir, there must be residual oil saturation even under the miscible gas injection,  $S_{orm}$  defined by Spence and Watkins (1980). In this paper, the concept of  $S_{orm}$  is defined as the residual oil saturation that does not decrease less than physically acceptable values under both miscible and immiscible conditions.

To model the  $S_{orm}$  in the framework of an equation of state, we double the fluid-component system over the originally defined one (see Fig. 1). The additional components are dedicated to model the  $S_{orm}$  and assigned with the EOS parameters identical to the originally defined components. Kim assigned the independent components for injection-gas components (Kim 1993), but we make similar assignments for the immobile components. In other words, the EOS was split, and two sets of identical EOS parameters and different compositions coexist.

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**Fig. 1—Partition of the fluid-component system to accommodate the concept of immobile and nonvaporizing residual oil saturation.**

For the component  $i$  of the original EOS, after the component splitting, we prepare component  $i_A$  as a mobile component and component  $i_B$  as an immobile component. The overall mole fraction of component  $i$  is referred to as  $z_i$ . The mobile portion is  $z_{i,A}$ , and the immobile portion is  $z_{i,B}$ . In the initial condition, these initial mole fractions are referred to as  $z_{i,i}^*$ ,  $z_{i,A}^*$ , and  $z_{i,B}^*$ .

At the model initialization, it is assumed that no vapor phase exists in the system. This allows us to further assume that liquid-phase mole fractions ( $x_{i,B}^*$ ,  $x_{i,A}^*$ , and  $x_{i,B}^*$ ) are identical to those of overall mole fractions ( $z_{i,i}^*$ ,  $z_{i,A}^*$ , and  $z_{i,B}^*$ ). Thus, the mole ratio between  $z_{i,A}^*$  and  $z_{i,B}^*$  is set to be identical to the ratio between the mobile oil and the residual oil. In a process of gas injection, it is known that the remaining oil changes from the initial composition because of the mass transfer; however, we simply assumed that the residual oil remained the same because no contact by the injection gas is assumed due to dead-end pores. In addition, no mass transfer is assumed between the hydrocarbon components and the water component.

This relationship can be expressed in the following equations:

$$x_{i,A}^* \cdot x_{i,B}^* = z_{i,A}^* \cdot z_{i,B}^* = (S_{oi} - S_{orm}) : S_{orm} \quad \dots \dots \dots (1)$$

$$z_{i,A}^* + z_{i,B}^* = z_{i,i}^* \quad \dots \dots \dots (2)$$

**Transportation-Coefficient Setup.** The concept of the transport coefficient was introduced by Barker and Fayers (1994). This concept has been used to upscale compositional models (Christie and Clifford 1998; Ballin et al. 2002; Jerauld 1998). The transport coefficient relates the composition of the fluid flowing out of a gridblock to that within the block.

The mass-balance equation for hydrocarbon component  $i$  in a conventional compositional-simulation model can be written as follows for cells without sink or source:

$$\frac{\partial}{\partial t} (\phi F z_i) + \nabla \cdot (u_o \rho_o x_i + u_g \rho_g y_i) = 0, \quad \dots \dots \dots (3)$$

where  $F$  indicates the total hydrocarbon moles in a cell of interest.

When we adopt the concept of transport coefficients, this equation is modified by introduction of transport coefficients ( $\alpha$ ) in the flow terms as follows:

$$\frac{\partial}{\partial t} (\phi F z_i) + \nabla \cdot (\alpha_{oi} u_o \rho_o x_i + \alpha_{gi} u_g \rho_g y_i) = 0. \quad \dots \dots \dots (4)$$

As a result, the transport coefficients determine the relative velocity of a particular pseudocomponent in a simulation model.

In our new method, we use the transport coefficients to immobilize a particular component of an EOS system. By assigning the transport coefficient of zero to an immobile portion of a certain component, that portion is immobilized from a gridblock. On the other hand, the transport coefficient of unity makes no change in the flow velocity of the component. By this method, any mole fraction of any component can be completely immobilized from the gridblock. These can be summarized as follows.

$$\alpha_i = \begin{cases} 0 & \text{for dedicated immobile portion, } i_B \\ 1 & \text{for mobile portion, } i_A \end{cases} \quad \dots \dots \dots (5)$$

Then, substituting Eq. 5 into Eq. 4 yields

$$\frac{\partial}{\partial t} (\phi F z_i) + \nabla \cdot (u_{o,A} \rho_{o,A} x_{i,A} + u_{g,A} \rho_{g,A} y_{i,A}) = 0. \quad \dots \dots \dots (6)$$

Due to the assumption of Eq. 5, immobile residual oil remains in the initial composition,  $z_{i,B}^*$  ( $i=1,2, \dots, n$ ).

**Relative Permeability Modification.** Because the transport coefficient modifies the convection term of each component as shown in Eq. 4, the total velocity of the oil phase is also inevitably changed. Consequently, the history-matching result (or a period before the start of gasflooding) will be changed. In other words, the use of the transport coefficient requires the modification of the oil relative permeability to maintain the same flow rate.

Under waterflooding conducted in the undersaturated condition with no solubility of hydrocarbon components into the aqueous phase, there exists only a liquid phase in a hydrocarbon system. Comparing a liquid-phase convection term for component  $i$  between Eq. 3 and Eq. 6 yields

$$u_o \rho_o x_i = u_{o,A} \rho_{o,A} x_{i,A} \quad \dots \dots \dots (7)$$

It is required to maintain the viscosity, density, and pressure distribution of the liquid phase by use of  $S_{orm}$ ; hence,

$$\frac{u_{o,A}}{u_o} = \frac{k_{ro,A}}{k_{ro}} = \frac{x_i}{x_{i,A}} \quad \dots \dots \dots (8)$$

If we introduce the correction factor  $C$ , the modified relative permeability of oil can be written as follows by use of Eq. 1:

From Eq. 8, we put the correction factor  $C$  to be

$$C = k_{ro,A} / k_{ro} = x_i / x_{i,A} = S_o / (S_o - S_{orm}), \quad \dots \dots \dots (9)$$

where  $x_{i,A}$  is the mole fraction of movable oil and  $S_{orm}$  is the residual oil saturation by miscible flooding.

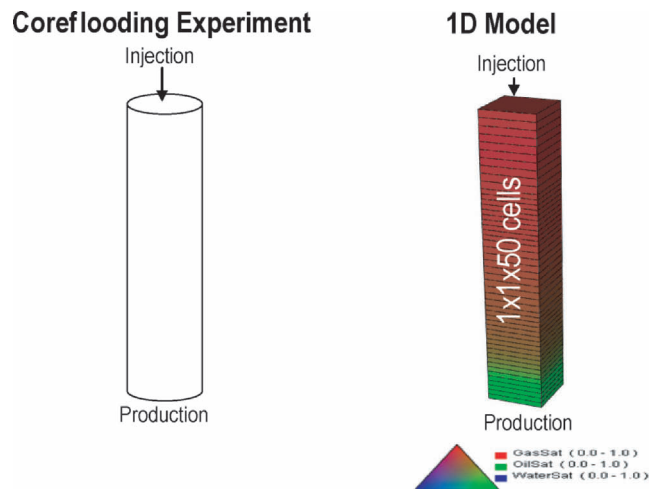
Then, the relative permeabilities are adjusted as follows:

$$k_{rog,mod} = C k_{rog} \quad \dots \dots \dots (10)$$

$$k_{row,mod} = C k_{row} \quad \dots \dots \dots (11)$$

**Testing the Developed Method by Use of a 1D Model**

**Model Description.** The developed method was tested by use of a 1D compositional-simulation model of coreflooding (1x1x50 cells) for the validation (see Fig. 2). In this test, three types of injectants were assumed: water, lean gas, and CO<sub>2</sub>. For each case, four different  $S_{orm}$  values (0, 0.1, 0.2, and 0.3) were assumed to see the sensitivity of  $S_{orm}$ . It should be noted that a  $S_{orm}$  of 0.0 stands



**Fig. 2—One-dimensional coreflooding model used to test the developed method.**

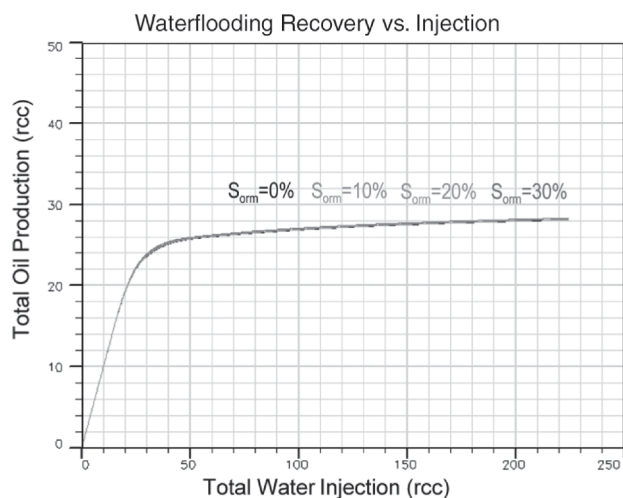


Fig. 3—Predicted waterflooding performance insensitive to  $S_{orm}$  by adjustment of oil-phase relative permeability where four different curves overlap each other among  $S_{orm}$  values of 0%, 10%, 20%, and 30% (rcc=reservoir condition  $cm^3$ ).

for the conventional simulation. The  $S_{orw}$  and  $S_{org}$  were both assumed as 0.348 for method-validation purposes.

**Water-Injection Case (Displacement Without Oil Vaporization).** Using the 1D coreflood model described above, the waterflooding experiment was simulated. As shown in Fig. 3, the developed method reproduced the result that was simulated with the conventional model ( $S_{orm} = 0$ ) in all cases. In addition, no spread of results between different sets of  $S_{orm}$  was observed in the waterflooding cases. Thus, we confirmed that the developed method does not affect the simulation results of water injection.

**Gas-Injection Case (Displacement With Oil Vaporization).** We tested the developed method against two gas-injection schemes: pure  $CO_2$  and lean gas ( $C_1$ : 75%). In contrast to the water-injection case, the sensitivity of  $S_{orm}$  was observed as the spread in the oil-recovery profiles among different sets of  $S_{orm}$  caused by the vaporization of oil (see Figs. 4 and 5). When  $S_{orm}$  is increased, the vaporization effect of oil by gas is suppressed. Consequently, we saw less recovery.

#### Requirement of $S_{orm}$ in Coarse-Scale Reservoir Simulation of Gas Injection

The use of  $S_{orm}$  in coarse-scale reservoir simulation is required because oil that cannot be contacted easily by the miscible gas is

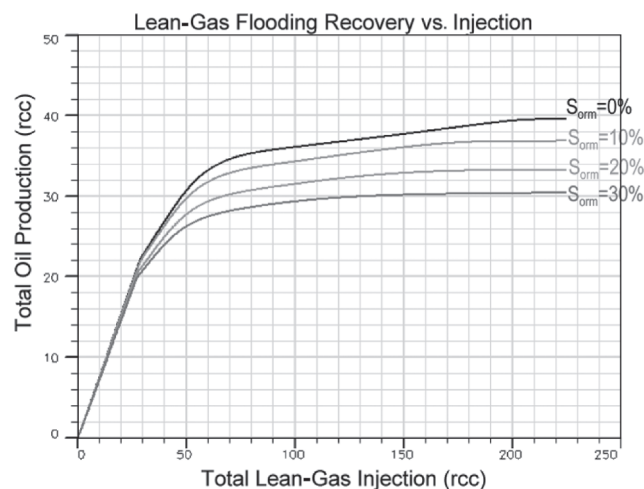


Fig. 5—Sensitivity of  $S_{orm}$  on lean-gas flood production performance by use of the coreflooding model.

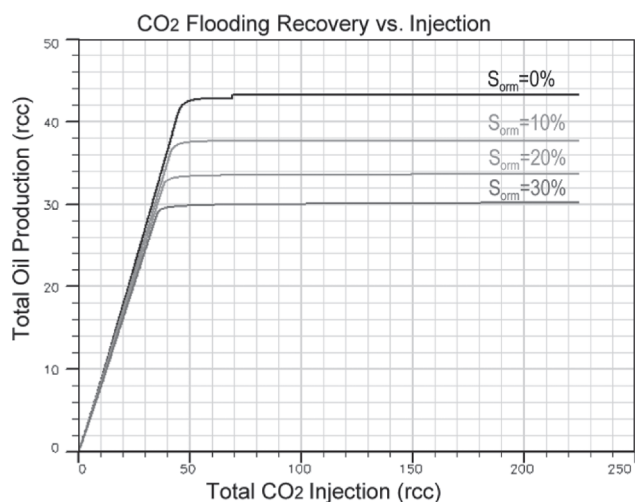


Fig. 4—Sensitivity of  $S_{orm}$  on  $CO_2$  flood production performance by use of the coreflooding model.

bypassed and, hence, not displaced. This bypassing is due to reservoir heterogeneity and preferential flow paths that prevent the injected gas from reaching such oil. It also implies that, as the reservoir characterization becomes more and more homogeneous as the grid becomes coarser and coarser, a larger  $S_{orm}$  is needed to reproduce the “heterogeneous” results.

To prove the discussion above, we carried out a numerical experiment using two different models: a coarse homogeneous model and a fine heterogeneous model. This coarse model is identical to the 1D coreflooding model used in the previous section (Fig. 2). The corresponding fine model was obtained by refining the coarse model with the dimension and the permeability distribution shown in Fig. 6. It should be noted that the average per-

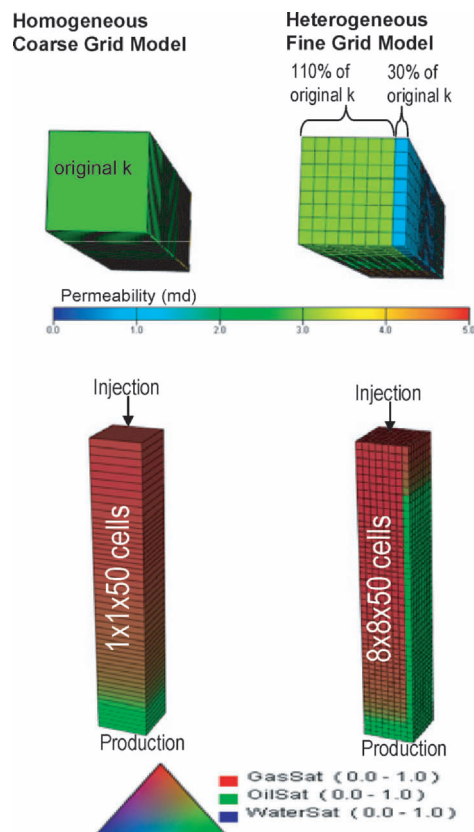


Fig. 6—Dimension and permeability distribution of the coarse model and the fine model.

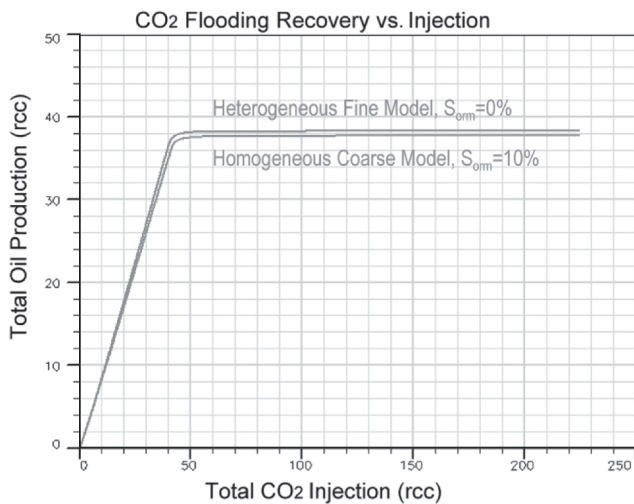


Fig. 7—Comparison in recovery performance between the coarse model and the refined model shown in Fig. 6.

meability is common between the coarse model and the fine model, while an  $S_{orm}$  of zero was assumed in the refined model. As shown in Fig. 7, the recovery profile in the fine model was almost identical to that of the coarse model, with an  $S_{orm}$  of 10%. This experiment clearly indicates that for field simulations,  $S_{orm}$  is an upscaling parameter that would change with grid resolution and heterogeneity.

### Application to the Real Reservoir Model

After the evaluation by use of a 1D simulation model, this method was applied to a sector model of a real reservoir to compare CO<sub>2</sub> injection and lean-gas injection while  $S_{orm}$  is varied along with the laboratory results. The overview of the sector model without defining  $S_{orm}$  is shown in Fig. 8. It can be seen that the vicinity of gas injectors shows oil saturation much lower than the prescribed  $S_{org}$  (30% in this case). This is because of the lack of restriction on the vaporization of oil from liquid phase to vapor phase.

In this model, a gas-injection scheme is started using horizontal gas injectors and horizontal producers after approximately 20 years of natural depletion. No gas was liberated during the primary depletion period because the oil is highly undersaturated. The natural-depletion period was already history matched.

With the new method,  $S_{orm}$  was varied among 15%, 20%, 25%, and 30%. The simulated production performances under the natural depletion and water injection almost have not changed irrespective of the varied  $S_{orm}$ .

In the prediction of the gas-injection scheme, we observed the distinct impact of the immobile oil incorporated by our new method. Fig. 9 shows the prediction result of production profiles

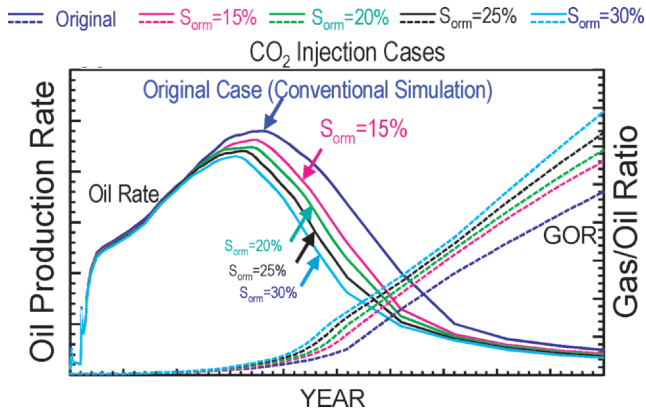


Fig. 9—Prediction results of the CO<sub>2</sub> flood case with several  $S_{orm}$  by use of the sector model.

### Horizontal Line-Drive Gas-Injection Case

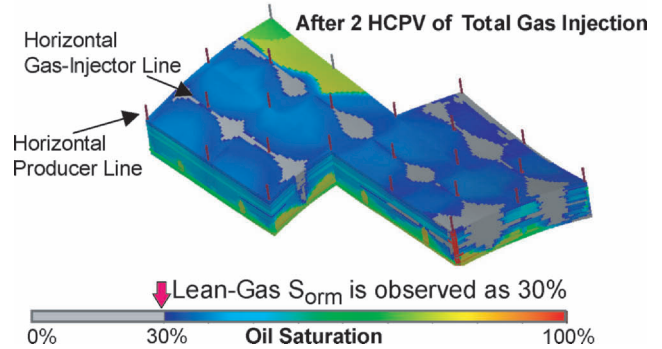


Fig. 8—Oil-saturation distribution predicted in the lean-gas flood with a real field sector model where  $S_{orm}$  proposed in this paper was not defined and oil saturation decreased far beyond the prescribed  $S_{orm}$  (30%).

under the CO<sub>2</sub> injection scheme. It clearly can be seen that the higher  $S_{orm}$  causes the lower oil-production rate and the higher gas/oil ratio with time. The lean-gas injection scheme showed a similar tendency with the increased  $S_{orm}$ .

In the laboratory coreflooding experiments using core samples from the real reservoir at pressures similar to the simulation described above, the  $S_{orm}$  obtained by CO<sub>2</sub> flooding was measured as approximately 15%, while the  $S_{orm}$  obtained by the lean-gas flooding was measured as approximately 30%. To evaluate the CO<sub>2</sub> injection case and the lean-gas injection case accounting for the laboratory results, we assumed these laboratory results as representative  $S_{orm}$  in this sector model. The results are shown in Fig. 10. Both injection schemes show a similar reduction in the recovery factor.

It should be noted that, in this sector-model simulation, we simply applied the laboratory coreflood results. However, it is suggested that  $S_{orm}$  be estimated by adopting past theoretical work [e.g., by Fayers (1988), who proposed the approximate method of miscible viscous fingering].

### Discussion

We have shown that our method successfully differentiated recovery performance along with the several  $S_{orm}$  values (see Fig. 9). In this paper, we made a simple assumption that the residual oil remains at the initial oil compositions as if the oil in the dead-end pore never contacts the injected gas. Hence, the transport coefficient of zero for the immobile components in Eq. 1 causes

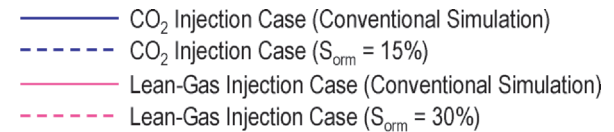


Fig. 10—Prediction by use of the sector model with  $S_{orm}$  based on laboratory results.

no compositional change in the residual oil and fulfills the assumed condition.

On the other hand, a flash calculation is conducted for any hydrocarbons contained in a simulation block, whether they are mobile or immobile. It cannot be avoided that a simulation block acts like one pressure/volume/temperature (PVT) cell. This also happens in our new method. Thus, the mobile and immobile portions are flashed together. Strictly, “uncontacted oil” is not exactly represented, though “immobile oil” can be modeled.

As studied by Cockin et al. (2000) and McGuire et al. (1995), nonzero residual oil saturation exists in gas injection, even under miscible conditions, as a result of bypassed oil or dead-end pores, namely those caused by reservoir heterogeneity. In the field scale compositional model adopting coarse cells, it is necessary to have reasonable residual oil saturation, while it is expensive to upscale fine-cell models. Because of this requirement, upscaled residual oil saturation in coarse cells was represented by the concept of  $S_{orm}$  featured as nonvaporizing immobile oil saturation. This was demonstrated in this paper, as shown in Figs. 6 and 7.

It is also possible to define the composition of  $S_{orm}$  as a spatial variable, although we assume that the composition of  $S_{orm}$  remains the same as the initial oil composition in this paper. The composition of  $S_{orm}$  is a consequence of mass transfer and phase equilibrium between different fluid systems. The light-intermediate components tend to transfer even from dead-end pores and, hence,  $S_{orm}$  can be dominated by heavy components. When the residual oil is made up of different compositions from the initial oil (e.g., due to vaporization of the light components), each component can have its specific transport coefficient. In such a condition, we would have to further generalize the relative permeability modification shown in Eqs. 10 and 11 because the correction factor in Eq. 9 is unique throughout the gas phase and the oil phase.

In addition, the prescribed  $S_{orm}$  obtained by partitioning of the fluid component can be spatially variable. Although  $S_{orm}$  was set constant throughout the model in this paper,  $S_{orm}$  can be a function of the composition of injectant, capillary number, temperature, and pressure provided that such source code is available. There should be sufficient database content regarding  $S_{orm}$  from laboratory and field data to describe  $S_{orm}$  as a function of those parameters above. Such a data library would allow us to assign variable  $S_{orm}$  by cells and even as a function of pressure and capillary numbers. For instance, in the vicinity of wellbore,  $S_{orm}$  can be different from that in other portions of the reservoir owing to higher fluid velocity and, hence, is less dominated by capillary forces.

Regarding the application of local grid refinement (LGR) in the vicinity of injectors, the effect is expected to depend on how subgrid scale heterogeneity is honored. LGR simply dividing coarse cells without assigning heterogeneity to refined cells will still decrease oil saturation less than unphysical values.

This method can be applied to both miscible and immiscible conditions. Because of the ability to restrict vaporization, this method can be powerful in field-scale models made up of coarse cells, though calculation time will be increased owing to a doubled fluid-component system. In our case, the calculation time and required memory were increased by approximately two times the original case. It also should be noted that this method theoretically requires the condition when  $S_{orm}$  is lower than  $S_{org}$  and  $S_{orw}$  though such a relation is unlikely to be violated in real data.

## Conclusions

We developed a novel method of incorporating and honoring residual oil saturation obtained in laboratory coreflood experiments. This residual oil was made nonvaporizing and immobile, applying the concept of the transport coefficient. The developed method has been tested for CO<sub>2</sub> and lean-gas injection. The results of this study can be summarized as follows:

1. The newly developed method is able to restrict vaporization beyond the prescribed residual oil saturation. Thus, the accurate evaluation of gasflooding is made available, reflecting the residual oil saturation derived from laboratory coreflood experiments.
2. A novel application of the transport-coefficient approach was developed, in which it was found that the adjustment of oil-

phase relative permeability was required to correctly simulate the model performance before gas injection.

## Nomenclature

$A$	= mobile phase
$B$	= immobile phase
$C$	= correction factor for $k_{row}$ and $k_{rog}$
$F$	= total hydrocarbon present (mol/unit pore volume)
$k_{rg}$	= gas relative permeability
$k_{rog}$	= oil relative permeability to gas
$k_{rog,mod}$	= modified oil relative permeability to gas
$k_{row}$	= oil relative permeability to water
$k_{row,mod}$	= modified oil relative permeability to water
$k_{rw}$	= water relative permeability
$n$	= number of components in the hydrocarbon system
$S$	= saturation
$S_o, S_g$	= oil- and gas-phase saturations
$S_{oi}$	= initial oil saturation
$S_{orm}$	= residual oil saturation by miscible flooding
$S_{orw}$	= residual oil saturations by water and gas
$S_{wir}$	= irreducible water saturation
$u_o, u_g$	= darcy velocity of oil and gas phases
$x_i$	= liquid-phase mole fraction of component $i$
$x_i^*$	= initial liquid-phase mole fraction of component $i$
$y_i$	= vapor-phase mole fraction of component $i$
$y_i^*$	= initial vapor-phase mole fraction of component $i$
$z_i$	= overall mole fraction of component $i$
$z_i^*$	= initial overall mole fraction of component $i$
$z_{i,A}$	= mobile-phase mole fraction of component $i$
$z_{i,A}^*$	= initial mobile-phase mole fraction of component $i$
$z_{i,B}$	= immobile-phase mole fraction of component $i$
$z_{i,B}^*$	= initial immobile-phase mole fraction of component $i$
$\alpha_{oi}, \alpha_{gi}$	= oil- and gas-phase transport coefficients for component $i$
$\phi$	= porosity
$\rho_o, \rho_g$	= oil- and gas-phase densities
$\nabla \bullet$	= divergence

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