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Compositional Three-phase Relative Permeability and Capillary Pressure Models Using Gibbs Free Energy

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# Compositional Three-phase Relative Permeability and Capillary Pressure Models Using Gibbs Free Energy

by

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## Thesis

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## Dedication

To my parents for their unconditional love and support, my brothers for their encouragement, and my grandparents for their inspiration.

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First and foremost, I would like to express my deepest appreciation to my supervisor, Dr. Gary Pope, for trusting me and accepting me in his research group. Working under a leading scientist is an unparalleled opportunity one can ever experience in their life and I cannot be more thankful for having this privilege. Of course, accomplishing the goals of this research in less than a year would not be possible without his excellent guidance, support and patience.

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### Abstract

# Compositional Three-phase Relative Permeability and Capillary Pressure Models Using Gibbs Free Energy

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Both relative permeability and capillary pressure depend on composition as well as saturation, but classical models neglect this dependence. The objective of this research was to develop coupled three-phase relative permeability and capillary pressure models for implementation in a four-phase flow compositional equation-of-state simulator. The models applied to several complex but practical reservoir simulation problems.

Models independent of phase label have many advantages in terms of both numerical stability and physical consistency. Identification of hydrocarbon and aqueous phases based on their molar Gibbs Free Energy (GFE) is a key feature of the new model. Instead of using labels (gas/oil/2nd liquid/aqueous) to define permeability parameters such as end points, residual saturation and exponents, the parameters are continuously interpolated between reference values using the Gibbs free energy of each phase at each time step. Consequently, the formulation used to implement other relevant physical parameters must be consistent with the new approach. A comprehensive but simple algorithm was developed for this purpose. The algorithm allows for very general threephase hysteresis in both relative permeability and capillary pressure.

An important part of this thesis is analyzing the results of a recent series of experiments on the effect composition on relative permeability. These new data were used to calibrate the new GFE relative permeability model and apply it in a compositional reservoir simulator.

The robustness of the new GFE model was shown through complex simulations such as solvent flooding, miscible/immiscible WAG processes, well stimulation processes using solvents to remove condensate and/or water blocks in both conventional and unconventional formations and other challenging applications involving both mass transfer between phases and phase changes. The interpolation of relative permeability parameters based on GFE instead of phase labels completely solves the discontinuity problem caused by phase flipping or misidentification. Therefore, simulations run significantly faster and are physically correct.

The novelty of this research is in integrating and unifying relevant physical parameters including trapping number, hysteresis and capillary pressure into one rigorous algorithm with compositional consistency and in the development and application of a practical procedure for numerical compositional reservoir simulations.

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## **Chapter 1: Introduction**

Simultaneous flow of three phases is involved in many subsurface processes such as water flooding in presence of free gas, miscible/immiscible Water Alternating Gas (WAG), solvents injection and CO<sub>2</sub> sequestration. Modelling of such physics is a key requirement for management and optimization of recovery process and reservoir surveillance. To accomplish this goal, robust modeling tools are required to be employed in reservoir simulators.

Accurate relative permeability and capillary pressure models are among the most critical requirements for description of multi-phase flow problems. Several relationships have been proposed for wide ranges of rock and fluid properties, but the complex nature of sub-surface flow physics still calls for more powerful techniques.

This chapter explains some serious limitations of existing models of three-phase flow in permeable media and outlines important features of a new Gibbs free energy dependent model. The framework of this thesis will also be presented at the end of this chapter.

#### **1.1 PROBLEM STATEMENT AND RESEARCH MOTIVATION**

Modelling of multi-phase flow in porous media requires knowledge of history-dependent governing relationships between fluid saturations (S), phase pressures (P) and relative permeabilities (kr). The procedure for two-phase flow is relatively straightforward since the saturation direction is either drainage or imbibition (or equivalently, decreasing and increasing saturation). When the saturation path is known, the relative permeability and capillary pressure depend only on one saturation and its historic direction.

Prediction of three-phase flow behavior is significantly more challenging. This is primarily due to an increase in the degrees of freedom for saturation changes. For three-phase flow , possible combinations of saturation direction increase to twelve cases of IDD, DID, DDI, DII, IDI, IID, CDI, CID, ICD, DCI, IDC and DIC where I, D and C designate increasing, decreasing and constant saturation conditions. Moreover, saturation trajectory in a three-phase space is defined by two independent saturation values leading to an unlimited number of paths. Therefore, both saturation direction and saturation path are required to be known in order to properly define three-phase relative permeability and three-phase capillary pressure.

Since measuring flow parameters from a three-phase experiment is a complex and time consuming procedure, three-phase relative permeability and capillary pressure models are often based on two-phase data. This simplification requires the two-phase parameters such as residual saturations to be corrected before being applied in a three-phase model (e.g. Fayers and Matthews 1984, Aleman 1986, Fayers 2000 and Yuan and Pope 2012). The other unavoidable modification is related to hysteresis. It is well known that the assumption of reversibility of drainage and imbibition processes used for two-phase hysteresis models cannot be directly used for three-phase flow models with arbitrary saturation paths (Larsen and Skauge 1998, Spiteri and Juanes 2004).

In reservoir simulators, different types of relative permeability and capillary pressure relationships are used for modeling of two, three and four-phase flow (Delshad and Pope 1989, Pejic and Maini 2003). The choice of models depends on the number of flowing phases, type of recovery process, dominant driving forces, reservoir rock and fluid characteristics amongst other factors.

Both two and three-phase models use various parameters such as endpoint relative permeabilities, exponents and residual saturations for specified oil, gas, second-liquid and aqueous phases. However, experimental observations show that the gas relative permeability is not the same for different gases (N2 vs CO2) even in the same rock under the same conditions (Dria et al. 1993). Yuan and Pope (2012) present a brief summary of additional evidence of compositional dependence based on reliable experiments reported in the literature. Jordan (2016) has recently completed experiments under very rigorous conditions and found there is a difference between N2 and CO2 relative permeability in the same core.

There are several major problems with traditional relative permeability models. Mass transfer between phases can cause large changes in phase compositions. In some cases, the phase

compositions become similar or even equal. The relative permeability of these phases should change continuously and approach the same value in such cases. The models do not generally behave this way or do so in a very limited and ad hoc way such as close to a critical point (Jerauld, 1997).

In compositional simulators, the phase label may change from one time step to another time step in the same gridblock for the same physical phase. This causes a discontinuity in the relative permeability of each phase. This is sometimes called phase flipping. Phase flipping causes numerical problems and is non-physical. These problems are difficult to solve even in the absence of hysteresis, but become even more difficult to solve with hysteresis and relatively little effort has been made to derive models without such limitations despite the obvious need and importance in compositional simulators. In compositional simulators, phase labeling is done after the number and composition of the phases are defined through stability and flash calculations. Therefore, failure in convergence of stability or flash calculations leads to additional problems with assigning physically correct relative permeability and capillary pressure values. The resulting discontinuities in calculated relative permeability and capillary pressure parameters significantly reduce numerical stability and increase computational time steps and are physically incorrect.

One more important concern regarding three-phase flow modeling is the proper choice of the capillary pressure model and its compatibility with the relative permeability model. Relative permeability is closely related physically to capillary pressure. Therefore, ensuring consistency between physical features such as hysteresis and compositional dependence is desirable but seldom enforced in commonly applied models.

This review accentuates the essential need of developing novel tools for better description of multi-phase flow problems. New approaches are needed to overcome the limitations of existing models so predictions will be closer to reality. At the same time, the models should be as simple and easy to use as possible consistent with this need. In particular,

3

the number of parameters in the models should be as small as possible so that it is feasible to estimate these parameters from limited and uncertain experimental data.

#### **1.2 THESIS GOALS AND OUTLINE**

This thesis presents a simple coupled formulation for three-phase relative permeability and capillary pressure for compositional reservoir simulation. The formulation, for the first time, incorporates hysteresis and compositional consistency for both capillary pressure and relative permeability models using a minimum number of input parameters. Unlike traditional models, the proposed Gibbs free energy approach is not affected by phase flipping and misidentification. The thesis is organized as follows:

In Chapter 2, a literature review of existing relative permeability and capillary pressure models for three-phase flow is presented and discussed.

Chapter 3 presents fundamentals and basic assumptions of the proposed relative permeability and capillary pressure models including their dependence on Gibbs free energy.

In chapter 4, concepts of compositional modelling of hysteresis effect in the GFE model are discussed. It starts with historic modelling of two-phase residual saturation and relative permeability and continues by extension of the models to more complex three-phase hysteresis.

In chapter 5, effects of Interfacial tension (IFT), viscous and gravitational forces on residual saturations and relative permeability are explained. The trapping number is defined as a proper measure of the balance between these forces. A new formulation is introduced to account for the dependence of the relative permeability parameters on this dimensionless group. A comprehensive algorithm integrating trapping number and hysteresis for use in compositional reservoir simulators is also described.

Chapter 6 presents a new three phase capillary pressure model valid over a wide range of rock wettability from water wet to mixed and oil wet conditions. The proposed model is compatible with the proposed relative permeability model and employs the same compositional consistency and hysteresis approaches.

In chapter 7, an analysis on results of a series of experiments recently completed at the Petroleum Engineering Department of the University of Texas at Austin is presented. The experiments include measurements of steady state two-phase relative permeability of brine/N2 and brine/CO2 in the same Berea sandstone core. It will be explained how the experimental data are processed to be applied in the new GFE model.

In chapter 8, the experimental data prepared in Chapter 7 are used for a field-scale numerical simulation. Several more simulation results are also presented to show the robustness of the developed relative permeability and capillary pressure models. It starts from relatively simple test cases such as gas injection for a three-component mixture to three and four-phase problems such as solvent flooding, miscible/immiscible WAG processes and well stimulation in conventional and unconventional gas condensate reservoirs.

The thesis is concluded in chapter 9 with the major conclusions of this research and a summary of the key features of proposed models and ideas for future studies and extensions.

## **Chapter 2: Literature Review**

Developing new models for three-phase flow in porous media has been always an area of strong interest for research. Several three-phase relative permeability correlations have been proposed in order to better describing such physics. These models include a wide range of variety from basic non-historic relationships to advanced phase label independent models with compositional consistency.

The focus of this study is on historic modelling of three-phase flow. This chapter presents a brief review on previously suggested three-phase relative permeability, capillary pressure and hysteresis models that are relevant to the scope of this research and the developed model.

### 2.1 THREE-PHASE RELATIVE PERMEABILITY MODELS

The first empirical correlation for prediction of oil relative permeability for a three-phase flow was proposed by Corey et al. (1956). They concluded that under experimental conditions that the effect of hysteresis is minimized by enforcing identical saturation paths, relative permeabilities of gas and water in a water-wet gas-oil-water flow primarily depend on their respective saturations. Their proposed model for oil relative permeability was limited to drainage process, where both water and total liquid saturations are decreasing, and was assumed to be a function of the two residuals and saturations.

$$k_{ro} = \frac{(S_L - S_W)^3}{(1 - S_{rL})^4} (S_W + S_L - 2S_{rL})$$
(2-1)

Where the  $k_{ro}$  is relative permeability of oil,  $S_w$  saturation of water,  $S_L$  saturation of liquid and subscript r for saturation refers to residual.

Naar and Wygal (1961) realized that hysteresis is affected by non-wetting phase trapping and modified Corey's model to develop a three-phase relative permeability relationship for imbibition, where water and total liquid saturations increase, by including gas initial saturation in their formulation. Land (1968) tried to unify previous studies on Initial Residual Curve (IRC) reported by Holmgren and Morse (1951), Dyes (1954), Kyte et al. (1956), Dardaganian (1957) and Crowell et al. (1966). In his relationship, maximum gas trapping is directly related to its maximum historical saturation.

$$S_{rg} = \frac{S_{gi}}{1 + CS_{gi}}$$
(2-2)

Where  $S_{gi}$  and C are the maximum gas saturation and Land's coefficient, respectively. He also presented another semi-empirical modification for Corey's model to calculate imbibition relative permeability using a pore size distribution parameter.

Corey's assumption about functionality of water, oil and gas relative permeabilities was repeated by Stone (1970) in his first empirical model. Among several modifications of Stone's model, the following equation suggested by Aziz and Settari (1979) is commonly used in simulators:

$$k_{ro} = \frac{S_{oe}k_{ro(w)}k_{ro(g)}}{k_{ro(rw)}(1 - S_{we})(1 - S_{ge})}$$
(2-3)

Where

$$S_{oe} = \frac{S_o - S_{om}}{1 - S_{wi} - S_{om}}$$
(2-4)

$$S_{we} = \frac{S_w - S_{rw}}{1 - S_{rw} - S_{om}}$$
(2-5)

$$S_{ge} = \frac{S_g}{1 - S_{rw} - S_{om}}$$
(2-6)

Where  $S_{om}$  is oil residual saturation in three-phase flow and  $k_{ro(rw)}$ ,  $k_{ro(w)}$  and  $k_{ro(g)}$ are the oil-water relative permeability measured at  $S_o = 1 - S_{rw}$ ,  $S_o = 1 - S_w$  and  $S_o = 1 - S_w$   $S_g - S_{rw}$  respectively. In this model, the residual saturations are defined as input parameters, which makes it more flexible for numerical simulations.

Later, Stone (1973) developed another model for three-phase oil relative permeability that makes use of four two-phase relationships and does not require residual saturations to be defined:

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) - k_{rg} - k_{rw}$$
(2-7)

Killough (1976) suggested that the endpoints of two-phase imbibition curves used in Stone's models can be calculated by Land's equation to account for hysteresis effect. He assumed that the imbibition curves are reversible and proposed a model for interpolation of intermediate points on relative permeability curves using an extra fitting parameter.

Carlson (1981) introduced an extension for Land's theory and calculated parallel bounding and scanning imbibition curves from a given primary drainage curve:

$$k_{rg}^{imb}(S_g) = k_{rg}^{drain}(S_{fg}) \tag{2-8}$$

Where  $S_{fg}$  is the saturation of free gas and is estimated by subtracting trapped gas determined by Eq. (2-2) from total gas saturation. Unlike Killough's and Land's correlations that used additional pore distribution or fitting parameters for definition of imbibition relative permeabilities, Eq. (2-8) does not require any further constant.

Lenhard and Parker (1987) used the scaled capillary pressure function of Van Genuchten (1980) in combination with corrected Mualem's (1976) two-phase relative permeability model to develope a new three-phase relative permeability relationship. They assumed that for water wet media, no gas-water interface occurs in three-phase region and implicitly added Land's hysteresis model in relative permeability by making use of apparent saturations which were assumed as saturation of one or two liquid phases plus trapped gas saturation of gas phase. They explained that this approach could account for the different effects that arbitrary saturation paths in three-phase space could have on relative permeability.

Baker (1988) proposed a three-phase model based on saturation weighted interpolation between the two-phase relative permeability values as follows:

$$k_{ro} = \frac{(S_w - S_{rw})k_{row} + (S_g - S_{rg})K_{rog}}{(S_w - S_{rw}) + (S_g - S_{rg})}$$
(2-9)

Where the two-phase relative permeabilities can be either experimental data or estimated by two-phase correlations. Delshad and Pope (1989) suggested a correlation in which the twophase relative permeability data are applied implicitly through residual saturations and saturation functions exponents.

Jerauld (1997) introduced a new idea that the relative permeability of a hydrocarbon phase should not depend on whether it is labeled oil or gas, but should depend instead on composition or physical properties of the phase and its saturation. To accomplish this goal, he used a measure of composition to interpolate between gas-water and oil-water limits. He defined the composition parameter as follows:

$$f_h = \frac{\xi_h - \xi_{gi}}{\xi_{oi} - \xi_{gi}}$$
(2 - 10)

Where  $\xi_{gi}$  and  $\xi_{oi}$  are parachor-weighted molar densities of immiscible gas and oil as reference conditions. At miscibility conditions, difference between gas and oil becomes arbitrary as their compositions approach each other. Hence, a key requirement for compositional consistency is to have only one hydrocarbon-water relative permeability,  $k_{rhw}$ , which is interpolated by  $f_h$  parameter and satisfies the following constraint:

$$k_{ri} = \frac{S_i}{(1 - S_w)} k_{rhw}(S_w)$$
(2 - 11)

Where  $k_{ri}$  is relative permeability of either oil or gas phases. He also proposed a modification of Land's model by adding one more empirical constant to Eq. (2-2) to achieve a better match with his experimental data for two-phase flow in the presence of a third phase

residual saturation. This modification was extended later by Beygi et al. (2015) to reflect cycle dependency of saturation hysteresis in a three-phase flow.

Fayers et al. (1984) added the compositional effect to a modified Baker's model and used phase densities to ensure a smooth transition in oil-water and gas-water relative permeabilities. They considered three separate regions with different compositional behaviors. The first region is strictly immiscible and no compositional effects are assumed. The second region is a compositional zone in where density is used as a compositional indicator for interpolation of gaswater and oil-water relative permeability. The third region is a near-miscible zone which is identified by a user defined critical capillary number and changes in the oil-gas relative permeability curves are also considered. To account for hysteresis, they regarded water and gas as primary driving phases and correlated hysteresis in relative permeability with maximum historic saturation of water and gas. Hence, by ignoring the effect of the oil phase on hysteresis, they used Killough's two-phase hysteresis relationship in their three-phase model.

In 1998, Larsen and Skauge assumed reversible scanning curves during drainage and imbibition displacements in a multi-cycle three-phase flow. They suggested that gas relative permeability in cycle n should be a function of both gas and water initial saturations at the beginning of the cycle:

$$\begin{bmatrix} K_{rg}^{Increasing}(S_g, S_w^I; S_g^{start}) \end{bmatrix}_n = \left\{ \begin{bmatrix} K_{rg}^{input}(S_g) - K_{rg}^{input}(S_g^{start}) \end{bmatrix} \left( \frac{S_{rw}}{S_w^I} \right)^{\alpha} \right\}_n + \qquad (2-12) \\ \begin{bmatrix} K_{rg}^{input}(S_g) \end{bmatrix}_{n-1} \end{bmatrix}$$

They also provided a new model for gas trapping in which residual gas could increase during each cycle even if its maximum historic saturation is constant.

Blunt (2000) employed a similar approach by using densities for interpolation between gas and oil limits during three-phase flow. For a small region near a critical point where miscibility is approached, he suggested an additional interpolation by capillary number to ensure single-phase flow of oil and gas. He also applied a different hysteresis model in his relative permeability relationship. In addition to using Land's equation for estimation of gas trapping in a water wet medium, he proposed the oil trapping be taken into account in order to differentiate between effect of different paths on saturation history. This is achieved by introducing a hydrocarbon phase as the sum of oil and gas phases and correlating its residual saturation to the maximum historic saturation through an equation identical to Land's model.

Yuan and Pope (2012) generalized the concept of compositional consistency and proposed a new three-phase relative permeability model which is applicable for any combination of phases including oil, gas, second liquid, solvent and aqueous phases. They used molar Gibbs free energy of each phase as the composition measure to interpolate relative permeability parameters between reference values and also as an alternative for phase identification instead of assigning phase labels. Their model did not include hysteresis, but they did mention the principle of how Land's equation could be used with the Corey model to include hysteresis with compositional consistency.

Beygi et al. (2015) used Jerauld's (1997) three-phase gas relative permeability correlation and extended it for an arbitrary phase j as follows:

$$k_{rj} = k_{rj}^{0} \frac{(1+C_{2j})\overline{S_{j}}^{C_{1j}}}{1+C_{2j}\overline{S_{j}}^{C_{1j}}(1+\frac{1}{C_{2j}})}$$
(2-13)

The relative permeability parameters in the above equation,  $k_{rj}^0$ ,  $C_{1j}$  and  $C_{2j}$ , are calculated through two subsequent linear interpolations. The first part is similar to Yuan and Pope's approach and uses GFE to interpolate between reference conditions. The calculated values are then applied in a saturation-weighted interpolation to define the three-phase parameters based on two-phase measured data. They also proposed a three-phase hysteresis model in which the cycle dependency is considered by making displaced phase trapping a function of displacing phase saturation at the beginning of cycle *n*. Although this approach helps to retain the shape of the relative permeability function during different cycles, it assumes two different terms for residual saturation and trapped saturation while the former is related to saturation path and the latter to saturation direction. This behavior does not seem consistent with

known physics. For example, with this assumption the trapped saturation is a monotonically increasing parameter that is not affected by trapping number and has a different functionality to composition and mass transfer between the phases. This is likely to cause unintended and unrealistic predictions by the model.

#### **2.2 THREE-PHASE CAPILLARY PRESSURE MODELS**

By comparison with three phase relative permeability models, few three-phase capillary pressure models have been proposed and tested with experimental data and even fewer three phase capillary pressure models have included hysteresis. Most of the models seem extremely arbitrary and simplistic with little if any physical basis or empirical validation.

Parker et al. (1987) modified a two-phase capillary pressure model for application to three phases. In their formulation, capillary pressure was assumed to be a function of wetting saturation only. They used a Land-type equation for oil and gas trapping using the same approach as they used in their relative permeability model (Lenhard and Parker, 1987).

Fayers et al. (2000) modeled oil-water and gas-water capillary pressure as functions of two saturations and used a density-weighted parameter to interpolate between gas and oil limits similar to their relative permeability model. As was discussed in the previous section, they ignored the effect of the oil phase on hysteresis and used Killough's two-phase model.

Hustad (2010) assumed that capillary pressure between each pair of phases can be described by two different functions depending on which phase saturation is used. Hence, a total of 6 independent functions can be defined and he suggested an algorithm to choose between several possible combinations for three phases.

Skjaeveland et al. (2000) developed a two-phase capillary pressure model for mixed-wet reservoirs in which capillary pressure between oil and water is a function of both saturations.

$$P_{c} = \frac{C_{w}}{\left(\frac{S_{w} - S_{rw}}{1 - S_{rw}}\right)^{a_{w}}} + \frac{C_{0}}{\left(\frac{S_{o} - S_{ro}}{1 - S_{ro}}\right)^{a_{o}}}$$
(2 - 14)

Where  $C_w$ ,  $C_o$ ,  $a_w$  and  $a_o$  are parameters chosen differently for drainage and imbibition directions.

Helland and Skjaeveland (2004) extended this two-phase model to three phases by using the base two-phase relationship for capillary pressure between each pair of phases. However, they did not explain how the coefficients used in the Eq. (2-14) can be calculated for three phases in which the number possible saturation directions is not restricted to two drainage and imbibition cases but rather an unlimited number of trajectories are possible.

Lack of consistency between hysteresis models used in capillary pressure and relative permeability is a common issue with all of these models. In addition, most of them are only applicable for a specific wettability condition. Hence, developing a general three-phase capillary pressure relationship to overcome these limitations was addressed in this research using the same general approach as used for relative permeability modeling with compositional consistency.

### **Chapter 3: New Relative Permeability Model Concepts and Assumptions**

The most fundamental concept of the new three-phase relative permeability model is the definition of phases and all relevant parameters based on molar Gibbs Free Energies (GFEs). This method has several advantages in comparison with using labels for phase identification and is able to capture the effect of composition on relative permeability parameters. The basic assumptions and features of the GFE relative permeability model are presented in this chapter. The effects of hysteresis and trapping number are discussed in later chapters.

#### **3.1 BASE THREE-PHASE RELATIVE PERMEABILITY MODEL**

The Corey equation was used to model the dependence of relative permeability on saturation because of its simplicity and because it is known to be a well behaved function. However, the same approach used in the new GFE model described in this chapter is general so it can be applied to any type of relative permeability function. The Corey model used here is similar to the Brooks-Corey (1964) expression, but developed for a wider range of rock and wettability characteristics. The endpoints, exponents and residual saturations in the Corey model can be adjusted to fit specific relative permeability data. The Corey equation is

$$k_{rj} = k_{rj}^0 \left( \frac{S_j - S_{rj}}{1 - S_{rl} - S_{rk}} \right)^{n_j} \tag{3-1}$$

Where the subscripts j, l and k refer to different phases,  $k_{rj}^0$  is the endpoint,  $n_j$  the normalized saturation exponent and  $S_{rl}$  and  $S_{rk}$  are the three-phase residual saturations. Equation (3-1) was modified compared to Yuan and Pope (2012) by omitting the residual saturation of phase j from the denominator. The reason for this modification is to ensure consistency between applied relative permeability and hysteresis models. This change is explained in chapter 4.

During injection of carbon dioxide in tertiary recovery processes, a second liquid phase rich with  $CO_2$  often forms at low temperature. In most of practical cases, only three phases flow in a typical single gridblock. However, the fourth phase can still affect the relative permeability because it occupies pore space even though it is not mobile. In this case, a more general form of the equation (3-1) can be used by including the residual saturation of the fourth phase in the denominator.

#### **3.2 THREE-PHASE RESIDUAL SATURATION**

Three phase residual saturations are typically less than two phase residual saturations (Fayers and Matthews 1984, Aleman 1986). Yuan and Pope (2012) modeled three phase residuals based on two phase residual saturations and the saturations of the other two phases as follows:

$$S_{rj}^{3P} = \min\left(S_j, S_{rj}^{2P}(1 - b_j S_i S_k)\right)$$
(3-2)

Where *b* is a fitting parameter and depends on wettability and composition of the phases. Path dependency of three-phase residual saturations can also have a significant effect on relative permeability. Fig. 3-1 depicts three contours of zero relative permeability (phase saturation is equal to its residual) assuming different fitting parameters. Although only convex isoperms are shown in the ternary diagram, concave isoperms can also be modelled with Eq. (3-2) by assigning negative values to *b*. In chapter 5, the three-phase residual saturation model is integrated with a hysteresis model and the results are compared with three-phase experimental relative permeability measurements.

#### **3.3 EVALUATION OF FLOW PARAMETERS USING MOLAR GFE**

Flow parameters such as relative permeability coefficients in Eq. (3-1) depend on phase properties, i.e. oil, gas, solvent, water (aqueous phase) or second hydrocarbon-rich liquid. This dependency is typically applied in reservoir simulators by making relative parameters functions of phase labels.



Figure 3-1: Contours of zero relative permeability for different fitting parameters.

Proper phase identification can sometimes become a highly challenging task in compositional reservoir simulation. In simulators, phase labels are assigned after the number of hydrocarbon phases are determined from a Gibbs stability test and followed by a flash calculation. This is generally not a problem when only one calculation is done using a robust algorithm and the results are interpreted by the user. However, when thousands of flash calculations are done during a compositional simulation, the same physical phase is sometimes label differently for different time steps in the same gridblock or in different gridblocks for the same time step. The consequent phase misidentification and flipping creates discontinuities in relative permeability values so the numerical results are physically incorrect and there may be numerical oscillations at the same time resulting in small time steps for even complete failure of the simulation.


Figure 3-2: Relative permeability parameters as: a) f(G): continuous function of molar GFE, b) h(ph - label): discontinuous function of phase labels.

A variety of algorithms for minimizing phase flipping were developed many years ago but they sometimes fail and they are more likely to fail for more complex problems involving extensive compositional changes such as happens when a solvent is injected into a gascondensate reservoir. Hence, using a label independent method for calculation of the parameters has a significant advantage over conventional label dependent approaches.

In the proposed model, different hydrocarbon phases are only identified by their molar GFE instead of phase labels and as a result, all relative permeability parameters such as endpoints, exponents and residual saturations are estimated by continuous functions of GFE as illustrated in Figure 3-2.

The molar Gibbs Free Energy of phase j (GFE) is a thermodynamic property and can be expressed in terms of composition, temperature, pressure and fugacity coefficients as follows:



Molar Gibbs Free Energy

Figure 3-3: Linear interpolation based on molar GFE between reference relative permeability parameter values.

$$G_{j} = \sum x_{ij} \left( \int_{T_{R}}^{T} C_{pij} dT - T \left( \int_{T_{R}}^{T} \frac{C_{pij}}{T} dT - R ln \frac{P}{P_{R}} \right) \right) + RT \sum x_{ij} \ln(x_{ij}) +$$
(3-2)  
$$RT \sum x_{ij} \ln(\widehat{\Phi}_{ij})$$

Where  $x_{ij}$  is mole fraction of component *i* in phase *j*, *T* is temperature, *P* is pressure,  $C_{pij}$  is molar heat capacity at constant pressure,  $\Phi$  the fugacity, R is the ideal gas constant and subscript R refers to the reference condition. When the reservoir temperature is constant, the reference temperature ( $T_R$ ) can be set equal to the reservoir temperature and equation (3-2) can be simplified as follows:

$$\frac{G_i}{RT} = \sum (x_{ij} \ln \frac{P}{P_R}) + \sum x_{ij} \ln(x_{ij}) + \sum x_{ij} \ln(\widehat{\Phi}_{ij})$$
(3-3)

The above non-dimensional expression is called molar GFE and is used as interpolation parameter. Equation (3-3) implies that this term is function of both composition and pressure.

Therefore, the new model is capable to capture both of the effects of composition and pressure on the relative permeability.

The functional dependence of relative permeability is not known in general and is difficult to derive from first principles. One simple option is to assume a linear function to interpolate between reference values. Using this approach (Figure 3-2), the interpolation is expressed as follows:

$$P_{j} = P_{1R} + \frac{G_{j} - G_{1R}}{G_{2R} - G_{1R}} (P_{2R} - P_{1R}), \text{ if } G_{1R} < G_{j} < G_{2R}$$

$$P_{j} = P_{2R} + \frac{G_{j} - G_{2R}}{G_{3R} - G_{2R}} (P_{3R} - P_{2R}), \text{ if } G_{2R} < G_{j} < G_{3R}$$

$$(3 - 4a)$$

$$(3 - 4b)$$

This method requires the values of the relative permeability parameters at reference states, which in turn should be based on experimental data. The reference states must be set wide enough so that all interpolation that is done during a simulation falls within these limits. This can be accomplished by simply running each particular simulation to determine the extremes of the GFE.

#### **3.4 EXAMPLES OF NON-MONOTONIC GFE BEHAVIOR**

One of the first questions that needed to be investigated was whether the GFE is a monotonic function of phase composition and pressure. A few test cases indicated that it is not always monotonic. Then the question arises whether this non-monotonicity has a significant effect on the interpolated relative permeability values. This issue is discussed below. A few static test cases with different levels of non-monotonic GFE behavior and how the interpolated relative permeability parameters were affected are described and discussed next. Although a comprehensive analysis calls for dynamic simulation integrating all affecting parameters, this static analysis is done just for insight and better understanding about general behavior of physical parameters of interest before extending the basic model with more advanced features such as trapping number, hysteresis and capillary pressure effects as described in the following chapters.

In the examples below, we show only the endpoint relative permeability parameter, but it is important to note that all parameters must be interpolated using GFE to avoid discontinuities in the relative permeability.

# 3.4.1 Case 1: Pressure variation in 4-Component mixture

Table 3-1 and Figure 3-4 show fluid composition and phase envelope for case 1.

Component	Mole Fraction
C <sub>1</sub>	0.80
nC <sub>4</sub>	0.15
C <sub>7</sub>	0.038
C <sub>10</sub>	0.012

Table 3-1: Mole fractions for case 1.



Figure 3-4: Phase envelope for case 1, created by PVTSim Nova.



Figure 3-5: Normalized Molar Gibbs free energy (G/RT) (left) and interpolated endpoint relative permeability for gas and liquid phases (right) for Case 1.

Figure 3-4 presents the normalized GFE and the endpoint relative permeability interpolated using the GFE as a function of pressure at  $150^{\circ}$  F. The slight non-monotonic behavior of the gas GFE results in a non-monotonic behavior of the gas endpoint relative permeability.  $k_{rg}$  decreases from its maximum at 0.83 to about 0.81 by increasing the pressure. This change is far less than the uncertainty in the value of  $k_{rg}$  so in this example it is not of any practical significance.

### 3.4.2 Case 2: Pressure variation in Solvent Mixture

Table 3-2 shows fluid components of case 2 and Figure 3-5 shows a pressurecomposition diagram for a CO2/LNG solvent mixed with a crude oil (Guler et al. 2001). The mixture forms VL, VLL and LL phases for different solvent fractions and pressures at constant temperature. More details for the crude oil and solvent properties are available in section 8.4. Figures 3-7 and 3-8 depict molar GFE and the interpolated endpoint relative permeability values for Case 2 respectively for a mixture made from 80% solvent.

Component	Fraction
$CO_2$	0.815
C <sub>3</sub>	0.0043
C <sub>2</sub>	0.038
nC <sub>4</sub>	0.0798
nC <sub>5</sub>	0.0522
nC <sub>6</sub>	0.0267
nC <sub>7-9</sub>	0.022

Table 3-2: Solvent mole fractions for case 2.



Figure 3-6: Phase diagram of solvent-initial oil mixture at 80°F.



Figure 3-7: Normalized Gibbs free energy for case 2.



Figure 3-8: Interpolated endpoint relative permeability for the case 2.

All values are monotonic within the two phase regions and within the three phase region, but the endpoint relative permeability of L2 goes through a slight maximum. This nonmonotonic behavior is much smaller than typical uncertainties in experimental relative permeability data.

### 3.4.3 Case 3: Composition change in 3-Component mixture

For case 3, the focus is on composition change of a three-component mixture. Compositions of primary fluid and secondary mixture that is mixed with the fluid are given in Tables 3-3 and 3-4. Figure 3-9 shows a ternary diagram at 260 F and 1960 psi with contours of constant GFEs. It is important to emphasize relative permeability is only defined in the multiphase region where the mixture splits into gas and oil phases, which is illustrated on the ternary plot by red and blue curves, respectively. Figure 3-9 shows that the oil portion of the envelope is crossed by GFE contours for two times implying a non-monotonic behavior for this phase. Figure 3-10 shows the normalized GFE and endpoint relative permeability interpolated between the primary mixture composition (0.01 mole fraction CO2) and the secondary mixture composition (0.538 mole fraction CO2).

Component	Mole Fraction
CO <sub>2</sub>	0.01
C <sub>1</sub>	0.49995
C <sub>6</sub>	0.49995

Table 3-3: Primary solution mole fractions for case 3.

Table 3-4: Secondary solution mole fractions for case 3.

Component	Mole Fraction
CO <sub>2</sub>	0.53816
C <sub>1</sub>	0.18384
C <sub>6</sub>	0.27800



Figure 3-9: Normalized Gibbs free energy (left) and interpolated endpoint relative permeability (right) for Case 3. This question was raised by Shell Inc. experts during a personal communication.



Figure 3-10: Normalized GFE and interpolated endpoint relative permeability for the case 3.

The minimum in the oil GFE leads to a minimum in the oil endpoint relative permeability.  $k_{ro}$  decreases from 0.47 to 0.40 before increasing again as the critical point is approached. Whether this is large enough to matter depends on the problem. However, this type of static analysis indicates the extreme limits of composition change that may not apply to a typical simulation. The fluid properties analyzed in this part will be used in Chapter 8 for a dynamic simulation at reservoir conditions to evaluate the maximum effect of non-monotonic behavior for a typical simulation.

# **3.5 SUMMARY**

- A generalized Corey-type model was used to investigate the dependence of three-phase relative permeability on GFE. A key feature of new model is identification of all phases based on their molar GFEs instead of arbitrary phase labels. All relative permeability parameters such as residual saturations, endpoint relative permeabilities and exponents are separately estimated by linear interpolation between reference values of GFE.
- At constant reservoir temperature, molar GFE change is an explicit function of pressure and composition. However, the effect of temperature is implicitly embedded in the phase compositions.
- The residual saturation of a phase in three-phase flow is affected by the saturations of the other two phases. This dependence is modeled by modification of two-phase residuals through Eq. (3-2).
- Molar GFE change is not always a monotonic function of pressure or composition. However, for the example test cases the effect of non-monotonic behavior on the relative permeability interpolated with GFE was less than the typical uncertainty of relative permeability data.

# **Chapter 4: Hysteresis Effect**

Hysteresis in general refers to irreversibility or path dependence of a physical change in a system. In reservoir multi-phase flow, it manifests itself through strong dependency of relative permeability and capillary pressure on displacement path. Hysteresis can have a significant impact on reservoir performance for a wide variety of secondary and tertiary oil recovery processes. Furthermore, since many displacement processes involve mass transfer between the phases, including the compositional effect in the hysteresis model is of great interest.

In this chapter, a method for historic modelling of residual saturations and relative permeability in two-phase flow using GFE is explained. The compositionally consistent model is then extended to account for three-phase saturation effect to be applied in three-phase flow with arbitrary saturation paths and wettability conditions. Cycle dependency in three-phase flow is then discussed and an additional treatment is suggested to capture this effect.

#### **4.1 TWO-PHASE HYSTERESIS**

A change in displacement direction affects the trapping of phases in multiphase flow in permeable media. In addition to the residual saturations, relative permeability can also be significantly affected by hysteresis. In this section, the effect of two-phase hysteresis on residual saturations and relative permeability is discussed.

### 4.1.1 Two-Phase Historic Residual Saturation

Initial Residual Curves (IRC) relate the residual saturation of a phase to its maximum historic saturation. Fig. 4-1 shows some IRC experimental measurements reported by Ma and Youngren (1994). This is one of the most fundamental relationships related to hysteresis in porous media. Land modeled the IRC using the following equation:

$$S_{rg} = \frac{S_{gi}}{1 + \left(\frac{1}{(S_{rg})_{max}} - 1\right) S_{gi}}$$
(4 - 1)



Figure 4-1: Initial Residual Curve (IRC) of phase *j*.

Where  $S_{rg}$  is the residual gas saturation and  $S_{gi}$  is the initial gas saturation.  $(S_{rg})_{max}$  is the maximum residual gas saturation. As illustrated in Fig. 4-1, the experimental data show a plateau for the IRC as the initial saturation approaches higher values while Land's equation gives a non-zero slope and diverges from data points. Ma and Youngren (1994) modified the slope of IRC at high saturations by adding an empirical constant to Eq. 4-1 as follows:

$$S_{rg} = \frac{S_{gi}}{1 + \left(\frac{1}{(S_{rg})_{max}} - 1\right) S_{gi}^{b'}}$$
(4 - 2)

Jerauld (1997) made another modification to Land's equation:

$$S_{rg} = \frac{S_{gi}}{1 + \left(\frac{1}{(S_{rg})_{max}} - 1\right) S_{gi}^{1 + \frac{b'(S_{rg})_{Max}}{1 - (S_{rg})_{Max}}}}$$
(4 - 3)

Both of these equations require an additional empirically defined parameter. In the absence of enough experimental data, the parameter b in Eq. (4-2) can be estimated by satisfying the following constraint:

$$\frac{dS_{rg}}{dS_{gi}}|_{S_{gi}=1} = 0 \tag{4-4}$$

Taking the derivative of Eq. (4-4) and substituting the calculated b in Eq. (4-3) gives the following residual saturation relationship generalized for an arbitrary phase j:

$$S_{jr} = \frac{S_{ji}}{1 + \left(\frac{1}{(S_{rj})_{max}} - 1\right) S_{ji}^{\frac{1}{1 - (S_{rj})_{Max}}}}$$
(4 - 5)

This expression guarantees an unconditional slope of zero in IRC at the initial saturation of 1 and matches the experimental data shown in Fig. 4-1. Notice that the maximum residual saturation,  $(S_{rj})_{Max}$ , is interpolated from reference values using GFE so it includes the compositional effect. In the new three-phase GFE model, Eq. (4-5) is used to calculate the residual saturation of each phase for any given initial saturation of the same phase. However, Eq. (4-3) or (4-4) could be used if needed to match specific experimental data when such data are available.

### 4.1.2 Two-phase Historic Relative Permeability

Relative permeability in two-phase immiscible flow consists of increasing and decreasing bounding and scanning curves. Notice that we avoid using drainage and imbibition terms due to their ambiguity about the wettability of the phases. Furthermore, these two terms cannot sufficiently describe saturation direction of a three-phase flow, which will be explained later in this chapter. Fig. 4-2 shows primary increasing and scanning relative permeability curves of phase j for the case when the porous medium is initially fully saturated with phase i.



Figure 4-2: Increasing bounding and scanning two-phase relative permeability curves.

By injection of phase j, a continuous flow forms through connected pores. Under this condition, the flowing fraction of phase j is equal to its total saturation and the Corey-type correlation can be used to describe the primary increasing curve:

$$k_{rj} = k_{rj}^{end} \left(\frac{s_j}{1 - s_{ri}}\right)^{n_j} \tag{4-6}$$

The injection of phase j is continuous until the first saturation reversal occurs. At this point, the displacement direction is reversed and phase i is injected (D1 in Fig. 4-2). Once the saturation reversal starts, phase j is subjected to gradual entrapment by phase i. The trapped portion of phase j increases from zero at the beginning of the reversal to its maximum value by the end of the process, which is indicated by  $S_{rj1}^{Max}$  in Fig. (4-2) and is calculated from Eq. (4-5). Hence, the saturation of phase j varies between its initial saturation and its residual saturation.

The flowing saturation, which is defined by subtracting the trapped portion of the phase from its saturation, can be calculated based on Eq. (4-5):

$$S_{fj} = \frac{1}{2} \left[ \left( S_j - S_{rj} \right) + \sqrt{\left( S_j - S_{rj} \right)^2 + \frac{4}{\left( \frac{1}{(S_{rg})_{max}} - 1 \right)} \left( S_j - S_{rj} \right)} \right]$$
(4 - 7)

The next step is to define an expression for the decreasing relative permeability curve. Carlson (1981) proposed that decreasing curves can be generated using the primary increasing function and flowing saturation of phase j:

$$k_{rj}^D(S_j) = k_{rj}^I(S_{fj}) \tag{4-8}$$

The above equation implies that the value of decreasing relative permeability corresponding to  $S_j$  can be determined by entering the increasing curve with  $S_{fj}$ . Combining Eq. (4-8) with Corey-type relationship given in Eq. (4-6) results in the following expression:

$$k_{rj}^{D}(S_j) = k_{rj}^{end} \left(\frac{S_{fj}}{1 - S_{ri}}\right)^{n_j}$$

$$(4 - 9)$$

A simpler way to think about the above equation is that the saturation term used in the numerator is the flowing saturation. Since during primary increasing of phase j no entrapment has occurred, the flowing and total saturation are the same. Hence, Eq. (4-9) can be always used for calculation of relative permeability of phase j after defining the  $k_{rj}^{end}$  and  $n_j$  from primary increasing curve.

The saturation reversal could take place at any other saturation on the primary increasing saturation curve. Therefore, numerous scanning curves can originate from the primary increasing curve with different initial and residual saturations. All scanning curves can be described by Eq. (4-8) in a similar way as was explained for the first scanning decreasing curve. It should be noted that in this approach all scanning curves are assumed parallel to each other (D1 and D2 in Fig 4-2).



Figure 4-3: Comparison of relative permeability data with curves calculate from model during first increasing, first decreasing and second increasing displacements. Experimental data reported by Braun and Holland (1995).

If another reversal happens and phase j is injected again, the decreasing scanning curve is retraced until the maximum historic saturation is achieved. After this point, the primary increasing curve is followed again. The assumption of reversible scanning curves was first introduced by Killough (1976) and also later used by Carlson (1981). However, they did not support it by showing any experimental data.

To verify the validity of the above assumptions in deriving bounding and scanning relative permeability curves, a set of empirical data reported by Braun and Holland (1995) was used. They performed a series of two-phase measurements on a water-saturated Berea sandstone

core and reported oil relative permeabilities during primary increasing, primary decreasing and secondary increasing displacements as presented in Fig 4-3.

Eq. (4-6) was employed to determine the relative permeability measurements during the first gas increasing displacement. The calculated parameters were then substituted into Eq. (4-9) to find the oil decreasing relative permeability. The derived curve shows good agreement with measured data as illustrated in Fig. (4-3). Once the oil residual saturation is achieved by the end of decreasing process, the saturation direction is reversed again and a second increasing curve begins. The experimental results indicate a small deviation between the two subsequent decreasing and increasing curves. However, assuming reversible scanning in two-phase flow is a reasonable simplification and helps reduce the number of parameters required to model relative permeability hysteresis.

# 4.2 THREE-PHASE HYSTERESIS

A description of hysteresis in three-phase flow is more challenging since the degrees of freedom in saturation direction increase and since the path dependence must also be taken into consideration. Unlike two-phase flow, saturation directions in three-phase space are not adequate to define displacement trajectories and two independent saturations values are required. Fig. 4-4 depicts two different displacement paths, AB and AC, on a ternary diagram with identical initial points. Both displacements are identified as IDI processes where the letters refer to saturation direction of phase i, j and k, respectively. The key question is how will the different paths taken to get from point A to point B affect the residual saturation and relative permeability of phase j at point B?

The answer to this question clarifies the difference between two and three-phase hysteresis modelling and how both the saturation path and direction in three-phase space affect the relative permeability. In the next section, residual saturation and relative permeability models are discussed. Capillary pressure models are described separately in the Chapter 6.



Figure 4-4: Alternative saturation displacement paths in three-phase flow.

# 4.2.1 Hysteresis in Three-phase Saturation

As shown in Chapter 3, three-phase residual saturations can be modeled with the following simple equation:

$$S_{rj}^{3P} = \min\left(S_j, S_{rj}^{2P} (1 - b_j S_i S_k)\right)$$
(4 - 10)

The above relationship indicates that three-phase residual saturations depend on two independent saturation values. In Fig. 4-4, the saturation of phase j at both points B and C has decreased from 0.8 to 0.2, but the residual saturations will be different according to Eq. (4-10). The change in residual saturation depends on parameter  $b_j$ , which is a function of wettability, composition and pressure of phase j, and controls the curvature of isoperms (Fig 3-1). However, this relationship by itself does not account for hysteresis. If an additional path is taken from point C to point B, the residual saturation of all phases at the end of ACB will be as same as that of AB.

The effect of saturation direction and trapping during saturation reversal can be taken into account by calculating  $S_{rj}^{2P}$ , the two-phase residual saturation, using Land's approach. This method for integrating (4-10) with the IRC offers a very simple and convenient way to take both saturation direction and path dependencies into consideration. This approach makes it clear that the residual saturations at the end of ACB and AB displacements are not the same since the two different paths result from different maximum historic saturations for phase *i*.

# 4.2.2 Hysteresis in Three-phase Relative Permeability

The effect of hysteresis on the Corey-type three-phase relative permeability function is applied through changes in residual saturations as follows:

$$k_{rj} = k_{rj}^0 \left( \frac{s_j - s_{rj}^{3p}}{1 - s_{ri}^{3p} - s_{rk}^{3p}} \right)^{n_j} \tag{4-11}$$

Where all the three-phase residual saturations indicated by superscript 3*p* are calculated as described in section 4.2. Eq. (4-11) implies that relative permeability for three-phase flow is implicitly affected by saturation direction and saturation path. For the case of two displacement trajectories illustrated in Fig. 4-4, relative permeability values along AB and ACB are clearly different even if phase compositions and pressures are kept the same. Furthermore, if the saturation displacements are reversed and the saturation trajectories are retraced toward point A, the resulting relative permeabilities will be far different from the initial values at the beginning of the displacement process.

Figures 4-5 to 4-7 present the results of two and three-phase relative permeability measurements on a water-wet Berea sandstone core reported by Oak (1990). The three-phase experiments were performed for subsequent DDI and IID displacements where the letters refer to saturation direction of water, oil and gas, respectively. The water and gas relative permeability experimental data show no significant difference between two and three-phase flooding results while there is a considerable shift in oil relative permeability since oil is the intermediate wetting

phase. Hence, the value of parameter *b* in Eq. (4-10) is set to zero for water and gas phases and a positive value is assigned to oil by matching the function with the corresponding data points. This is also illustrated in Fig. 4-8 through contours of zero relative permeabilities corresponding to  $b_o = 2.7$ ,  $b_g = 0$  and  $b_w = 0$ .

Eq. (4-11) was used to calculate the three-phase relative permeability curves based on Oaks's reported measurements. It should be emphasized that all phase compositions, pressures and trapping numbers are assumed to be constant during the entire displacement process and the residual saturations only vary by hysteresis parameters including saturation direction and path. The results depicted in Figs. 4-5 to 4-7 show good agreement with the reported experimental data. This means that the proposed simple hysteresis model can properly combine the three-phase residual model (Eq. 4-10) with Land's equation to predict the three-phase relative permeability. This model also includes the compositional effect since all phase dependent parameters are interpolated from reference values using molar GFEs. It should be emphasized that in both two and three-phase models, there is only one term to represent the residual saturation of each phase affected by saturation path and direction. This critical constraint ensures the consistency in applying the effects of composition and also trapping number, which will be discussed in the next chapter.

#### **4.3 CYCLE DEPENDENCE EFFECT**

The proposed hysteresis model described in section 4.2 implies that the assumption of reversible scanning curves in Carlson's model is not necessarily valid in three-phase flow. This is primarily attributed to irreversibility of three-phase residual saturations as discussed in section 4.2. In multicycle displacements such as WAG, this effect manifests itself through cycle dependency of residual saturation and relative permeability.



Figure 4-5: Two and three-phase gas relative permeability data reported by Oak (1990).



Figure 4-6: Two and three-phase oil relative permeability data reported by Oak (1990).



Figure 4-7: Two and three-phase water relative permeability data reported by Oak (1990).



Figure 4-8: Contours of zero relative permeability for oil, water and gas phases.

There are some methods in the literature suggesting additional treatments for the cycle dependence of relative permeability and residual saturation. The most practical model has been proposed by Larsen and Skauge (1998). They assumed that in a water-wet medium, gas relative permeability during each cycle depends on the saturation of water at the beginning of the cycle. We generalize their formulation by applying it for an arbitrary phase of j and making it a function of its conjugate (displacing) phase saturation,  $S_l^I$ . The increasing relative permeability in cycle n is given as:

$$\begin{bmatrix} k_{rj}^{Increasing}(S_j, S_l^I; S_j^{start}) \end{bmatrix}_n = \left\{ \begin{bmatrix} k_{rj}^{input}(S_j) - k_{rj}^{input}(S_j^{start}) \end{bmatrix} \begin{pmatrix} \frac{S_{rl}}{S_l^I} \end{pmatrix}^{\alpha_j} \right\}_n + \begin{bmatrix} k_{rj}^{input}(S_j) \end{bmatrix}_{n-1}$$

$$(4 - 11)$$

The first bracket on the right side of Eq. (4-11), which includes a subtraction of two relative permeability terms, represents a vertical shift to relative permeability curve. The second parenthesis is a reduction part, which accounts for the reduction of phase *j* relative permeability in the presence of flowing displacing phase. The  $\alpha_j$  is a fitting parameter which depends on wettability and composition and is interpolated by GFE between reference values as explained in chapter 3. The last term in the above equation is the stopping point of the last hysteresis loop and ensures continuity between subsequent loops. A similar approach is applied for calculation of residual saturations. Eq. (4-7) is modified as follows:

$$(S_{fj})_{n} = \frac{1}{2} \left[ (S_{j} - S_{rj}) + \sqrt{(S_{j} - S_{rj})^{2} + \frac{4}{\left(\frac{1}{\left(S_{rj}^{shift}\right)_{n}} - \frac{1}{\left(S_{ij}^{shift}\right)_{n}}\right)}} (S_{j} - S_{rj}) \right]$$
(4 - 12)

Where the shifted variables are evaluated in the following way:

$$\left(S_{j}^{shift}\right)_{n} = \left(S_{j}\right)_{n} - \left(S_{j}^{end}\right)_{n-1}$$

$$\left(4 - 13 a\right)$$

$$\left(S_{j}^{shift}\right)_{n} = \left(S_{j}\right)_{n} - \left(S_{j}^{end}\right)_{n-1}$$

$$\left(4 - 13 b\right)$$

$$\left(S_{j}^{shift}\right)_{n} = \left(S_{j}\right)_{n} - \left(S_{j}^{end}\right)_{n-1}$$

$$(4 - 13c)$$

The flowing saturation is then calculated as:

$$\left(S_{fj}^{shift}\right)_{n} = \left(S_{fj}\right)_{n} + \left(S_{j}^{end}\right)_{n-1} \tag{4-14}$$

Eq. (5-8) can now be used in conjunction with Eq. (5-14) to calculate relative permeability as:

$$k_{rj}^D(S_j) = k_{rj}^I(S_{fj}^{shift}) \tag{4-15}$$

The above simple algorithm only requires one more empirical parameter,  $\alpha_j$ , and is compatible with the GFE model. Hence, in cases when cycle dependency plays a role, this model can be used to account for that effect.

Beygi et al. (2015) modelled both hysteresis and cycle dependency in three-phase flow by defining two separate terms to reflect saturation path and direction effects. For saturation path, they used Eq. (4-10) to determine historic three-phase residual saturations and made it a function of composition. For modelling of phase entrapment resulting from a change in saturation direction during subsequent cycles, they introduced a monotonically increasing term with a different functionality to composition. The advantage of this method is to retain the shape of the relative permeability curve during multiple cycles. However, splitting the residual saturation into different terms is not consistent with known physics. It is also in conflict with the principal structure of the new GFE relative permeability model, so Larsen et al.'s approach was used for modelling of cycle dependency.

# 4.4 SUMMARY

- The history dependence of two-phase flow relative permeability can be described by the saturation direction of only one phase since the displacement path is already known. For three-phase flow, two independent saturations are required and both saturation direction and saturation path contribute to relative permeability hysteresis.
- The initial residual curve (IRC) relates the residual saturation of a phase to its historic maximum saturation. Land's original equation and its modified forms for characterization of the IRC are widely used in multi-phase hysteresis models.
- Carlson's hysteresis model was modified for use in the GFE model for modelling of twophase hysteresis. This approach is based on reversibility of scanning and bounding increasing and decreasing curves.
- In three-phase flow, the residual saturations calculated from Land's equation must be modified to consider the effect of saturation path. The resulting three-phase residual saturation is then used in the GFE model to calculate the relative permeability.
- Cycle dependency in the residual saturation and relative permeability plays a role in some recovery processes such as WAG, so this effect was also included into the GFE model by generalizing Larsen's cycle dependent model.

# **Chapter 5: Scaling Relative Permeability Using Trapping Number**

In previous chapters, the basics of the GFE relative permeability model were introduced and then it was explained how two and three-phase hysteresis effects were included in the model. In this chapter, a new formulation is introduced to implement the trapping number in the new GFE three-phase relative permeability model. The chapter starts with a review of how the change in the ratio of viscous and gravitational forces to interfacial (IFT) force at reservoir conditions affect residual saturations and relative permeability and then continues with an explanation of why the trapping number model is the best way to account for the effect of these forces on the residual saturations and relative permeability.

### **5.1 DEFINITION OF TRAPPING NUMBER**

Trapping number  $(N_{T_l})$  quantifies the balance of viscous and gravitational forces acting on a phase trapped by capillary forces in a pore throat i.e. the residual saturation. This dimensionless parameter is evaluated by vector summation of capillary number  $(N_{c_l})$  and Bond number  $(N_{B_l})$ . The capillary number is defined as the ratio of viscous forces over capillary forces and the Bond number is defined as the ratio of buoyancy forces over capillary forces. The details are explained below.

### 5.1.1 Capillary Number

Brownell and Katz (1947) realized that residual oil saturation should be a function of the ratio of viscous to interfacial forces and introduced a capillary number to capture this ratio:

$$N_{c_l} = \frac{|\bar{k}.\vec{\nabla}\Phi_l|}{\sigma_{ll'}} \tag{5-1}$$

Where subscripts l' and l refer to displacing and displaced phases,  $\overline{k}$  is the permeability tensor at unit saturation,  $\vec{\nabla} \Phi$  the flow potential gradient and  $\sigma$  the IFT between conjugate phases, the pair of displacing and displaced phases. A high value of capillary number means the displacement forces dominate over the capillary forces (low IFT) and low values mean the

opposite (high IFT). Notice the contact angle was not included in this definition. Although wettability certainly affects residual saturations, it is difficult to accurately incorporate this effect in the capillary number.

IFT in general depends on pressure, temperature and phase composition. The IFT between two hydrocarbon phases is estimated from the Macleod-Sudgen equation as reported by Reid et al. (1987):

$$\sigma_{jl} = 0.016018 \sum_{i=1}^{n_c} \psi_i (c_j x_{ij} - c_l x_{il})$$
(5-2)

Where  $\sigma_{jl}$  is the interfacial tension between phases *j* and *l* in dynes per cm,  $\psi_i$  the parachor of component *i*,  $c_j$  the molar density of phase *j* in lb-mole per cubic feet and  $x_{ij}$  the mole fraction of component *i* in phase *j*. Although pressure and temperature do not appear explicitly in Eq. (5-2), they implicitly affect the parachor and composition of each phase.

# 5.1.2 Bond Number

The Bond number is defined as the ratio of the buoyancy force to the capillary force:

$$N_{B_l} = \frac{kg(\rho_{l'} - \rho_l)}{\sigma_{ll'}} \tag{5-3}$$

Where g and  $\rho$  are gravitational constant and phase density. Bond number captures the pore level effect of gravity. Therefore, it matters even in a linear horizontal core. Similar to capillary number, high and low values for Bond number indicates weather surface tension is dominate or not.

### 5.1.3 Trapping Number

Pope et al. (2000) explained that in special cases such as vertical flow, the force vectors are collinear and one can just add the scalar values of the viscous and buoyancy forces and relate residual saturation to this sum. Another possibility is that one force is negligible compared to the other force and only the capillary number or Bond number can be used by itself. However, in a

general case in which force vectors are not necessarily collinear, a vector sum must be used. This generalization for capillary and Bond numbers was derived by Jin (1995) and called the trapping number and later generalized by Pope et al. (2000) as follows:

$$N_{T_l} = \frac{|\bar{k}.(\vec{\nabla}\phi_{l'} + g(\rho_{l'} - \rho_l)\vec{\nabla}D)|}{\sigma_{ll'}}$$
(5-4)

Where  $\vec{\nabla}D$  refers to depth gradient. Trapping number as expressed in the above equation can change by several orders of magnitude from its lowest values in an immiscible flow with small pressure displacing forces to the highest values achieved where IFT drops dramatically. Therefore, it should be used as indicator of dominant forces at a wide range of reservoir conditions.

# 5.2 EVALUATION OF RELATIVE PERMEABILITY USING TRAPPING NUMBER

Relative permeabilities are commonly measured at low pressure gradients and high IFT corresponding to low trapping number. This condition is not always valid at reservoir conditions. Surfactant flooding is a well-known exception. However, it is far from the only exception. Trapping numbers are typically high (above the critical trapping number for desaturation) for gas and condensate phases near production wells. Even very high rate water injection can exceed the critical trapping number near injection wells. This is in fact common for carbonate reservoirs because a wide pore size distribution is commonly found in carbonates. When miscible solvents are injected for enhanced oil recovery, it is common for most of the fluid contact in the reservoir to be below miscibility pressure and thus IFT and trapping number are again important. In fact, the default assumption should be that the trapping number should be considered in reservoir simulations of all kinds unless proven otherwise. Thus, relative permeability data and correlations need to be scaled using the trapping number before being applied at reservoir conditions. Many reservoir simulators include capillary number effects, but in a simplistic way (e.g. velocity form) and rarely do they include a trapping number model even though it is more

general than capillary number and it is hard to anticipate when buoyancy can be neglected and when it cannot.

Bloom et al. classifies the commonly used methods of scaling relative permeabilities into two main groups. The first approach is to interpolate between conventional immiscible relative permeability curves and a so-called miscible curve. Although there is no physical sense to define relative permeability at miscibility conditions where there is only one flowing fluid, a fictional function is often used in numerical simulators. Several authors have made use of this simple but physically incorrect approach by employing IFT or capillary number dependent variables as an interpolation parameter.

A major problem with the interpolation model as reported by Bloom et al. (1998) is the behavior of residual saturations. Since the residual saturation vanishes in limit of infinite capillary number or very low IFT, interpolation between miscible and immiscible curves gives a non-zero relative permeability for any saturation above zero. This assumption is physically unreal and may have undesirable consequences when the correlation is used in simulations. The other limitations of this method have been studied by Al-Zayer (2015). He explained that although scaling of residual saturations and relative permeability endpoints might be used as possible solutions, there are not physical reasons for some of these treatments.

The second main approach for modification of relative permeability curves is to interpolate the relative permeability data and/or the functional parameters in a model (e.g. the Corey model) with the trapping number. In this method, each relative permeability parameter such as the residual saturation, endpoint relative permeability and exponent for each phase is allowed to change independently as a separate function of trapping number. This approach ensures a smooth transition between different trapping number values. In this work, the trapping number is used in the Corey-type model with the trapping parameters dependent on GFE to ensure compositional consistency.



Figure 5-1: Schematic of residual saturation of wetting and non-wetting phases as function of trapping number. Dashed lines indicate the critical trapping numbers of each phase.

### 5.2.1 Trapping Number Dependent Corey Coefficients

Pope et al. (2000) used the trapping number expression in Eq. (5-4) to model residual saturation of phase l as follows:

$$S_{rl} = \min(S_l, S_{rl}^{high} + \frac{S_{rl}^{low} - S_{rl}^{high}}{1 + T_l (N_{T_l})^{\tau_l}})$$
(5-5)

Where  $S_{rl}^{low}$  and  $S_{rl}^{high}$  are residual saturations of phase *l* measured at high and low trapping numbers.  $T_l$  and  $\tau_l$  are the trapping model parameter and exponents used to modify the function shape. In practice,  $S_{rl}^{high}$  and  $\tau_l$  are typically zero and 1.0. The reason of taking the minimum in Eq. (5-5) is that mass transfer can reduce the value of  $S_l$  to values less than  $S_{rl}$ .

Figure 5-1 shows an example for plots of residual saturations versus trapping number for wetting and non-wetting phases. An intermediate phase is expected to lie between these two lines. The dashed lines indicate critical trapping number of each phase in which the effect of trapping number on residual saturations begins to be sensed.



Figure 5-2: Relative permeability endpoints of wetting and non-wetting phases as function of trapping number, dashed lines indicate critical trapping numbers of each phase.

The non-wetting phase trapping number parameter, shown by T in Eq. (5-5), is typically larger than that of wetting phase by about one order of magnitude. Therefore, the non-wetting phase reaches the critical threshold at lower trapping numbers compared to wetting phase.

The next step is to apply the trapping number to calculate other relative permeability parameters. Assuming a Corey-type relative permeability model, the endpoint relative permeability is modeled in a predictable way to increase with trapping number as shown in the following equation:

$$k_{rl}^{0} = k_{rl}^{0 \ low} + \frac{s_{rl'}^{low} - s_{rl'}}{s_{rl'}^{low} - s_{rl'}^{high}} (k_{rl}^{0 \ high} - k_{rl}^{0 \ low})$$
(5-6)

Where  $k_{rl}^{0 high}$  and  $k_{rl}^{0 low}$  are relative permeability endpoints measured at high and low trapping numbers. Relative permeability exponents are also calculated using the same approach:

$$n_{l} = n_{l}^{low} + \frac{s_{rl'}^{low} - s_{rl'}}{s_{rl'}^{low} - s_{rl'}^{high}} (n_{l}^{high} - n_{l}^{low})$$
(5 - 7)



Figure 5-3: Relative permeability exponents of wetting and non-wetting phases as function of trapping number, dashed lines indicate critical trapping numbers of each phase.

Where  $n_l^{high}$  and  $n_l^{low}$  are high and low trapping number exponents. Figs. 5-2 and 5-3 illustrate two examples of relative permeability endpoint and exponent versus trapping number.

Applying trapping number in Eq. 5-5 to 5-7 creates a sensible functionality for all relative permeability parameters. In Fig. 5-4, two relative permeability curves belonging to extremely low and intermediate trapping number values are plotted. This example illustrates the flexibility of this model in ensuring smooth transitions between different conditions.



Figure 5-4: Effect of trapping number on relative permeability curves.

# 5.2.2 Compositional Consistency in Trapping Number Model

The final step to make use of the trapping number dependent functions in the new GFE relative permeability model is to add compositional consistency. To accomplish this goal, all high and low trapping number coefficients employed for calculation of relative permeability parameters are separately interpolated by molar Gibbs free energy between reference values as explained in section 3.2. In Eq. (4-5) given for residual saturation,  $S_{rl}^{high}$ ,  $S_{rl}^{low}$ ,  $T_l$  and  $\tau_l$  are individually interpolated between reference values. The same approach is applied for  $k_{rl}^{0 high}$ ,  $k_{rl}^{0 low}$ ,  $n_l^{high}$  and  $n_l^{low}$  in Eq. (4-6) and (4-7) for the endpoints and exponents. It should be emphasized that all calculations are independent of phase labels. The algorithm is as follows:

- 1. Two-phase historic residual saturations are calculated from Eq. (4-5)
- 2. Three-phase historic residual saturations are calculated using Eq. (4-10)
- 3. Trapping numbers are calculated for each phase from Eq. (5-4).
- 4.  $S_{rl}^{high}$ ,  $S_{rl}^{low}$ ,  $k_{rl}^{0\ high}$ ,  $k_{rl}^{0\ low}$ ,  $n_l^{high}$  and  $n_l^{low}$ ,  $T_l$  and  $\tau_l$  are interpolated between reference values based on molar GFEs.
- 5. Scaled Residual saturations are evaluated using Eq. (5-5).
- Scaled relative permeability endpoints and exponents are calculated from Eq. (5-6) and (5-7) using residual saturations of conjugate phases.
- 7. All parameters are substituted in Corey-type model.

The above steps are shown in Fig. 5-5.



Figure 5-5: General algorithm for calculation of relative permeability using GFE model.
### 5.3 SUMMARY

- Relative permeabilities and residual saturations are typically measured at very low trapping number conditions. The trapping number is then used to account for the effects of interfacial, viscous and gravitational forces on trapped phases and relative permeabilities under reservoir conditions.
- Trapping number is the most general dimensionless group to measure the balance between contributing forces at reservoir conditions. In general, it is derived by vector sum of Capillary and Bond numbers.
- A new algorithm was introduced to make use of trapping number for evaluation of relative permeability parameters in the new three-phase relative permeability model. In this method, all high and low trapping number coefficients are directly interpolated only by molar GFE and independently from phase labels.

# **Chapter 6: Three-Phase Capillary Pressure Model**

Capillary pressure and relative permeability are tightly integrated parts of multi-phase flow models and should obey consistent principles. Capillary pressure defines the pressure difference existing across the interface between two-immiscible phases. In general, capillary pressure is a function of rock wettability, porosity and permeability as well as composition and saturation history. In this chapter, a new general three-phase capillary pressure model is presented. This model is developed based on extension of a two-phase capillary pressure model proposed by Skjaeveland et al. (2000) for mixed-wet media and includes both compositional and hysteresis effects.

#### **6.1 CAPILLARY PRESSURE IN TWO-PHASE FLOW**

Many two-phase capillary pressure correlations are limited to either completely waterwet or completely oil-wet conditions and typically have two adjustable parameters. One parameter reflects the pore size distribution and controls the curvature of the function and the other parameter defines the entry pressure level. To overcome this limitation, Skjaeveland et al. (2000) proposed a new two-phase oil-water capillary pressure model for mixed-wet conditions. This correlation is defined as sum of two terms, each with two adjustable parameters:

$$P_{c,ow} = \frac{c_w}{\left(\frac{S_w - S_{rw}}{1 - S_{rw}}\right)^{a_w}} + \frac{c_o}{\left(\frac{S_o - S_{ro}}{1 - S_{ro}}\right)^{a_o}}$$
(6-1)

Where *a* is the pore distribution parameter and *c* the entry pressure level. During primary oil increasing displacement,  $c_o$  is set to zero and only the first term remains. A positive capillary pressure means that the oil phase has a higher pressure than of water. In this model, *a* and *c* can have different values in increasing and decreasing directions and consequently, two sets of parameters  $(a_w^i, a_o^i, c_w^i, c_o^i \text{ and } a_w^d, a_o^d, c_w^d, c_o^d)$  can be defined to describe the shape of the function. The advantage of this definition is in its flexibility in capturing the entire range of wettability. Fig. 6-1 shows primary increasing and bounding capillary pressure curves in

conjunction with primary hysteresis loop for a mixed-wet media. The two asymptotes correspond to the residual water saturation and the residual oil saturation where the capillary pressure goes to plus and minus infinity. The residual saturations can be calculated using Land's model as explained in section 5.2.



Figure 6-1: Primary increasing, primary decreasing and bounding capillary pressure curves for a mixed-wet media (Skjaeveland et al. 2000).

Skjaeveland et al.'s model also includes a detailed multi-step algorithm for modeling of scanning curves. The procedure ensures the continuity between primary, bounding and irreversible scanning curves during subsequent reversals. They verified the validity of their correlation and hysteresis loop logic by matching a series of capillary pressure experiments (Hammervold 1998).

#### **6.2 THREE-PHASE CAPILLARY PRESSURE**

A three-phase capillary pressure model is expected to define the pressure difference across the interface between each pair of the phases. Using i, j and k as subscripts of the three immiscible phases, Eq. (6-1) can be extended as follows:

$$P_{c,ij} = \frac{c_i}{\left(\frac{S_i - S_{ri}}{1 - S_{ri}}\right)^{a_i}} + \frac{c_j}{\left(\frac{S_j - S_{rj}}{1 - S_{rj}}\right)^{a_j}}$$
(6 - 2 a)

$$P_{c,ik} = \frac{c_i}{\left(\frac{S_i - S_{ri}}{1 - S_{ri}}\right)^{a_i}} + \frac{c_k}{\left(\frac{S_k - S_{rk}}{1 - S_{rk}}\right)^{a_k}}$$
(6 - 2 b)

$$P_{c,jk} = \frac{c_j}{\left(\frac{S_j - S_{rj}}{1 - S_{rj}}\right)^{a_j}} + \frac{c_k}{\left(\frac{S_k - S_{rk}}{1 - S_{rk}}\right)^{a_k}}$$
(6 - 2 c)

Where the a constants have positive values and the sign of the c coefficients depends on the wettability of the phases. These equations are written as though each phase is in contact with both of the other phases. However, that is not true in a specific pore containing all three phases.

By definition, the three capillary pressures are related by the following constraint:

$$P_{c,ij} = P_{c,ik} + P_{c,kj}$$
(6-3)

Hence, two capillary pressures are determined independently from any pair of Eqs. (6-2a) to (6-2c) and the third capillary pressure is determined from Eq. (6-3).



Figure 6-2: Three-phase capillary pressure surface as a function of two independent saturations.

This approach to modeling three-phase capillary pressure makes sense from a fundamental point of view and also makes it easier to enforce continuity and consistency from two to three phases. The traditional or common approach involves adding additional empirical equation for three phase capillary pressure with more parameters and more complexity and little if any physical basis. It should also be emphasized that the new model is novel since all a and c constants depend on phase compositions and are interpolated between reference values using molar GFEs as illustrated in Fig. 3-1.

Capillary pressure is a function of two independent saturations when there are three phases present in the pores. Fig. 6-2 depicts a surface plot representing the values of  $P_{c,ij}$  in a mixed-wet medium as a function of  $S_i$  and  $S_j$  as expressed in Eq. (6-2a) without residual saturations. An important assumption considered in this plot is reversibility of scanning curves. This results from assuming identical *a* and *c* parameters during different saturation directions.



Figure 6-3: Phase *j* primary increasing and bounding decreasing three-phase capillary pressure surfaces as a function of two independent saturations ( $b_i = b_j = b_k = 0$ ).

The reason for such simplification is that in three-phase saturation space, prediction of the behavior of scanning curves is significantly more complex than for two-phase saturation space. As result, extension of the multi-step algorithm proposed by Skjaeveland et al. for description of irreversible scanning curves is very complicated and not practical in three-phase flow simulations. However, ensuring the continuity between primary increasing and scanning curves is still a critical requirement.

Fig. 6-3 shows primary increasing and bounding surfaces of three-phase capillary pressure with residual saturations. Both surfaces are described by Eq. (6-2a) using two independent saturations. However,  $c_j$  is set to zero for the primary increasing surface. All scanning curves resulting from saturation reversal on primary increasing surface are expected to

lie between the surfaces. Fig. 6-4 depicts selected contours of constant  $S_k$  from the primary increasing and scanning capillary pressure surfaces in Fig. 6-3.

Point R on Fig. 6-4 indicates a displacement reversal and the corresponding scanning curve initiated from the primary increasing curve. To ensure the continuity during transition between the two curves at point R, the following constraint must be satisfied:

$$\frac{c_i}{\left(\frac{S_i^R - S_{ri}}{1 - S_{ri}}\right)^{a_i}} = \frac{c_i}{\left(\frac{S_i^R - S_{ri}^*}{1 - S_{ri}^*}\right)^{a_i}} + \frac{c_j}{\left(\frac{S_j^R - S_{rj}}{1 - S_{rj}}\right)^{a_j}}$$
(6-4)

The  $S_{rj}$  and  $S_{ri}$  in the above equation are calculated from Eq. (5-10). Hence, the only unknown parameter is  $S_{ri}^*$  which is defined by solving the equation. The value of  $S_{ri}^*$  approaches  $S_{ri}$  as the reversal point becomes close to the residual saturation of phase *i*.

#### **6.3 SCALING CAPILLARY PRESSURE TO RESERVOIR CONDITIONS**

In previous sections, the two and three-phase capillary pressure models were presented and the effect of hysteresis was discussed. The next step is to scale the capillary pressure values to reservoir conditions. For arbitrary phases of i and j, the effects of rock porosity and permeability, contact angle and interfacial tension are included as follows:

$$P_{c,ij} = \sigma_{ij} \cos \theta_{ij} \sqrt{\frac{\Phi}{K}} \left( \frac{c_i}{\left(\frac{S_i - S_{ri}}{1 - S_{ri}}\right)^{a_i}} + \frac{c_j}{\left(\frac{S_j - S_{rj}}{1 - S_{rj}}\right)^{a_j}} \right)$$
(6-5)

The residual saturations in equation 6-5 are scaled with the trapping number using the same procedure explained in Chapter 5. In addition to the compositional effect in residual saturation, all phase-dependent constant parameters in Eq. (6-5) including  $c_i$ ,  $a_i$ ,  $c_j$  and  $a_j$  are interpolated between reference values using GFE.



Figure 6-4: Primary increasing (red), bounding decreasing (blue) and scanning (black)  $P_{cji}$  curves at constant  $S_k$ .

### **6.4 SELECTION OF REFERENCE PHASE**

In simulation of multiphase flow, a reference pressure is required in order to solve the pressure equation. Once the pressure of reference phase is calculated, the pressure of other phases can be calculated through two of the capillary pressure relationships given in Eq. (6-2). In many reservoir simulators including UTCOMP, the oil pressure is by default assumed as the reference pressure. This assumption requires the oil phase to always exist in all parts of the reservoir (all gridblocks in the model reservoir). Hence, it cannot be applied for simulation of gas or gas condensate reservoirs above the dew point, or even oil reservoirs when the oil phase is completely dissolved in some grid blocks due to mass transfer in miscible gas flooding.

In the new GFE model, the choice of reference pressure is based on wettability of the phases and the most wetting phase at each grid block is assumed as the reference pressure. The wettability of the phases can be compared using molar GFEs. One option is to assign the highest wettabilities to the lowest molar GFEs. However, this assumption can be changed depending on type of rock and fluid. For example, it is also possible to take the phase with intermediate GFE as the most wetting phase.

### 6.5 SUMMARY

- Capillary pressure and relative permeability should be modeled using consistent physical principles. These principles include compositional consistency and continuity.
- The two-phase capillary pressure model proposed by Skjaeveland et al. (2000) was extended and generalized to three-phases. The new model calculates the pressure difference across any pair of phases (Eq. 6-2) and can be used for any type of wettability.
- The compositional consistency approach used in the model is consistent with the relative permeability model. All phase dependent coefficients are interpolated between reference values using the molar GFE of each phase.
- The new three-phase hysteresis model for capillary pressure is also the same as that of the new GFE relative permeability model. The model includes the effects of saturation direction and saturation path on three-phase residuals and controls the location of asymptotes in three-phase capillary functions.

Ensuring continuity for the transition between primary increasing and scanning surfaces is an essential requirement. Eq. (6-4) is applied as an additional constraint at all saturation reversal points to avoid discontinuities in capillary pressure values.

## **Chapter 7: Analysis of Two-Phase Experimental Measurements**

A series of experiments has recently been completed in the Petroleum Engineering Department of the University of Texas at Austin (Jordan and Longoria, 2016) to measure steady state two-phase relative permeability of brine/N2 and brine/CO2 in the same Berea sandstone core. The purpose of these experiments was to determine under rigorous conditions if there is a significant effect of fluid composition and/or pressure on relative permeability. These new experimental data have been interpreted using the new GFE relative permeability model described in Chapter 3 and used in the numerical simulation study presented in Chapter 8.

#### 7.1 SUMMARY OF TWO-PHASE RELATIVE PERMEABILITY MEASUREMENTS

The purpose of coreflood experiments was to measure the steady state relative permeabilities of CO<sub>2</sub> and brine and N<sub>2</sub> and brine in Berea sandstone. All of the measurements were done at 104 °F (40 °C) and 1835 psi (126.5 bars). The brine contained 3 wt% NaCl + 0.1 wt% CaCl<sub>2</sub> as reported by Longoria et al. (2016). Primary increasing gas relative permeability measurements were done at three brine fractional flows: 0.5, 0.125 and 0. Primary decreasing gas relative permeability measurements were done at three brine fractional flows: 0.25, 0.5 and 1. The water saturations were measured using salinity tracer tests during co-injection experiments by changing the brine from 3 wt% NaCl + 0.1wt% CaCl2 to 6 wt% NaCl + 0.2wt% CaCl2.

They recorded four sectional pressure drops as well as the pressure drop across the whole core. The flood was considered to have achieved steady state if the pressure drop across the whole core did not change for at least 2 PVs of injected fluid. The general coreflood procedure for  $CO_2$  flood was provided by a personal communication form Rafael Longoria. Additional details will be included in the MS thesis by Paul Jordan when it is completed. The procedure is as follows:

- A Berea sandstone core of 1.875" diameter and 29.7cm length was cut and dried at 130°C until the mass did not change
- 2. Core was wrapped in heat-shrink Teflon, wrapped in a continuous sheet of aluminum foil four layers thick, and then wrapped in a secondary layer of heat-shrink Teflon.
- The core was loaded into the stainless steel core holder and a confining pressure of 3000psi was applied and leak checks were performed.
- The core was evacuated and then vacuum-imbibed with 6wt% NaCl + 0.2wt% CaCl2 brine. Approximate pore volume of the core was 91 ml.
- The pore pressure was increased by injecting additional 6wt% NaCl + 0.2wt% CaCl2 brine against 1800psi back-pressure. A salinity tracer test was then performed at 2mL/min flow rate at room temperature.
- Permeability to 3wt% NaCl + 0.1wt% CaCl<sub>2</sub> brine was measured at room temperature and approximately 1800psi back-pressure.
- 7. Core holder and fluid accumulators were heated to  $40^{\circ}$ C.
- Two pore volumes of CO<sub>2</sub>-saturated brine at 40°C and 1800psi were pumped into the core at 4 ml/min. The permeability to CO2-saturated brine was measured.
- 9. CO2-saturated 3wt% NaCl + 0.1wt% CaCl<sub>2</sub> brine and brine-saturated CO2 were coinjected into the core at a prescribed fractional flow until steady state was reached.
- 10. The water saturation was determined via a salinity tracer test by switching from 3wt% NaCl + 0.1wt% CaCl<sub>2</sub> (CO2-saturated) brine to 6wt% NaCl + 0.2wt% CaCl<sub>2</sub> (CO2-saturated) brine at the prescribed fractional flow. Afterwards, the injected brine was switched back to 3wt% NaCl + 0.1wt% CaCl<sub>2</sub> (CO2-saturated) in order to prepare the core for the next co-injection.
- 11. Step 9 and 10 were repeated for subsequent fractional flows.
- 12. At the end of all experiments, the core was degassed by slowly lowering the BPR dome pressure. Once the fluids were at atmospheric conditions, 3wt% NaCl + 0.1wt% CaCl<sub>2</sub>

brine was injected into the core against 1800 psi back-pressure in order to dissolve and remove residual CO2.

A similar procedure was used for  $N_2$  flooding. Fig. 7-1 shows s schematic diagram of the transducer manifold and the flow direction during gas flooding.



Figure 7-1: Transducer setup.



Figure 7-2: Relative permeability data for increasing N<sub>2</sub> and CO<sub>2</sub> saturations at 104°F and 1835 psi.

Fig. 7-2 shows the results of relative permeability measurements during increasing N2 and CO2 saturations in separate experiments on the same core and under the same conditions. All values have been reported for the whole core at steady state conditions. This graph clearly manifests a noticeable shift between the endpoints of the  $CO_2$  and  $N_2$  measurements from 0.69 to 0.56 which is equal to a 20% drop compared to  $CO_2$ . This change is attributed to the effect of composition on relative permeability parameters as was theoretically explained in chapter 3. They also measured the relative permeability of oil by injection of  $nC_{10}H_{22}$  into the same brine-saturated core at a lower pressure of 1500 psi. The results are shown in Fig. 7-3.



Figure 7-3: Relative permeability in increasing  $C_{10}$  saturations at 104°F and 1500psi.

### 7.2 PHASE BEHAVIOR AND GFE CALCULATIONS

The relative permeability measurements discussed in the previous section are now analyzed using the GFE model. . For this purpose, the first step is to calculate the composition of gas and aqueous phases at experimental pressure and temperature. At residual saturations, about 42 volume percent of the pore volume is occupied by gas. After converting this number to weight percent of  $CO_2$  and  $N_2$ , composition and fugacity of the phases can be calculated by PVTSim Nova using the Peng Robinson equation of state as presented in the following tables:

	H <sub>2</sub> O	NaCl	CaCl <sub>2</sub>	CO <sub>2</sub>
H <sub>2</sub> O				
NaCl	-0.217			
CaCl <sub>2</sub>	-0.202	-0.026		
CO <sub>2</sub>	0.095	2.100	2.23	

Table 7-1: Binary Interaction Coefficients of CO<sub>2</sub>-brine mixture.

Table 7-2: Properties of CO<sub>2</sub>-brine mixture at 104°F and 1835psi calculated using PREOS.

	Total	Gas	Aqueous	Unit
Mol%	100.00	34.66	65.34	-
Weight%	100.00	54.81	45.19	-
Molar Volume	0.56	0.96	0.35	ft³/lb-mol
Volume%	100.00	59.41	40.59	-
Density	49.2466	45.4316	54.8311	lb/ft <sup>3</sup>
Z Factor	0.1697	0.2909	0.1054	-
Molecular Weight	27.56	43.57	19.06	-
Enthalpy	-495.60	-87.84	-990.17	BTU/lb
Internal Energy	-13846.34	-4153.13	-18988.50	BTU/lb-mol
Internal Energy (Mass)	-502.50	-95.31	-996.36	BTU/lb
Entropy	-0.84	-0.33	-1.46	BTU/lb °F
Heat Capacity (Cp)	0.90	0.80	1.01	BTU/lb °F
Heat Capacity (Cv)	0.44	0.22	0.71	BTU/lb °F
Kappa (Cp/Cv)	2.03	3.68	1.42	-
JT Coefficient	-	0.0174	-0.0029	°F/psi
Velocity of Sound	-	1246.34	11107.82	ft/s
Viscosity	-	0.0766	0.6917	cP
Thermal Conductivity	-	0.05	0.37	BTU/(hr ft °F)
Interfacial Tension	-	15.68	15.68	dyn/cm

	Total mole %	Mole % in gas phase	Mole % in aqueous phase	fugacity in gas phase	fugacity in aqueous phase
H2O	63.896	1.681	96.548	1.01E+00	1.01E+00
NaCl	0.610	0.000	0.930	-	-
CaCl <sub>2</sub>	0.011	0.000	0.016	-	-
CO <sub>2</sub>	35.484	98.319	2.506	1.81E+03	1.81E+03

Table 7-3: Properties of CO<sub>2</sub>-brine mixture at 104°F and 1835psi calculated using PREOS.

Table 7-4: Binary Interaction Coefficients of N<sub>2</sub>-brine mixture.

	H <sub>2</sub> O	NaCl	CaCl <sub>2</sub>	$N_2$
H <sub>2</sub> O				
NaCl	-0.217			
CaCl <sub>2</sub>	-0.202	-0.026		
N <sub>2</sub>	0.48	3.200	2.290	

	Total	Gas	Aqueous	Unit
Mol%	100.00	13.35	86.65	-
Weight%	100.00	18.98	81.02	-
Molar Volume	0.74	3.31	0.34	ft³/lb-mol
Volume%	100.00	59.80	40.20	
Density	26.6457	8.4555	53.7003	lb/ft <sup>3</sup>
Z Factor	0.2243	1.0048	0.1041	-
Molecular Weight	19.70	28.01	18.42	-
Enthalpy	-841.77	7.43	-1040.65	BTU/lb
Internal Energy	-16835.07	-916.79	-19286.97	BTU/lb-mol
Internal Energy (Mass)	-854.52	-32.73	-1046.97	BTU/lb
Entropy	-1.30	-0.33	-1.52	BTU/lb °F
Heat Capacity (Cp)	0.88	0.29	1.02	BTU/lb °F
Heat Capacity (Cv)	0.62	0.19	0.72	BTU/lb °F
Kappa (Cp/Cv)	1.43	1.56	1.42	-
JT Coefficient		0.0143	-0.0030	°F/psi
Velocity of Sound		1281.06	11640.20	ft/s
Viscosity		0.0217	0.6935	сР
Thermal Conductivity		0.02	0.37	BTU/(hr ft °F)
Interfacial Tension		26.13	26.13	dyn/cm

Table 7-5: Properties of  $N_2$ -brine mixture at 104°F and 1835 psi calculated using PREOS.

Table 7-6: Properties of  $N_2$ -brine mixture at 104°F and 1835 psi calculated using PREOS.

	Total mole %	Mole % in gas phase	Mole % in aqueous phase	fugacity in gas phase	fugacity in aqueous phase
H2O	85.747	0.050	98.947	1.01E+00	1.01E+00
NaCl	0.818	0.000	0.944	-	-
CaCl <sub>2</sub>	0.014	0.000	0.017	-	-
$N_2$	13.420	99.950	0.092	1.81E+03	1.81E+03

While nitrogen shows almost no solubility in brine at  $104^{\circ}F$  and 1835 psi, the concentration of CO<sub>2</sub> in the aqueous at the same pressure and temperature is about 2.5 mole percent. Molar GFEs can be evaluated using Eq. (3-3). Notice that there is no need to add the temperature to the calculations as it is not expected to change during the displacement process and consequently, the reference temperature can be set to  $104^{\circ}F$ . The summary of the calculations for CO<sub>2</sub> and N<sub>2</sub> are presented in the following tables.

	Mole % in	Mole % in	Fugacity	Fugacity coef.	Molar GFE	Molar GFE
	gas phase	aqueous phase	coef. in gas	in Aqueous	in gas	in aqueous
H2O	1.681	96.548	3.21E-02	5.58E-04	-4.54E-02	-2.6053
NaCl	0.000	0.930	-	-	-	
CaCl <sub>2</sub>	0.000	0.016	-	-	-	
CO <sub>2</sub>	98.319	2.506	4.81E-01	1.89E+01	4.010	1.022E-01
Total	100.00	100.00	-	-	3.9646	-2.5031

Table 7-7: Molar GFE calculations for CO<sub>2</sub>-brine mixture at 104°F and 1835psi.

Table 7-8: Molar GFE calculations for N<sub>2</sub>-brine mixture at 104°F and 1835psi.

	Mole % in gas phase	Mole % in aqueous phase	Fugacity coef. in gas	Fugacity coef. in Aqueous	Molar GFE in gas	Molar GFE in aqueous
H2O	0.050	98.947	1.11E+00	5.58E-04	-1.33E-03	-2.6463
NaCl	0.000	0.944	-	-	-	
CaCl2	0.000	0.017	-	-	-	
$N_2$	99.950	0.092	9.84E-01	1.07E+03	4.8082	4.40E-03
Total	100.00	100.00	-	-	4.8068	-2.6419

The same procedure was followed to calculate the molar GFE of oil phase in  $nC_{10}$ -brine mixture. The results are presented in the following tables.

	Total	Oil	Aqueous	Unit
Mol%	100.00	11.10	88.90	-
Weight%	100.00	49.05	50.95	-
Molar Volume	0.69	3.44	0.35	ft³/lb-mol
Volume%	100.00	55.07	44.93	
Density	46.3096	41.2467	52.5146	lb/ft <sup>3</sup>
Z Factor	0.1570	0.7791	0.0793	-
Molecular Weight	32.13	142.01	18.41	-
Enthalpy	-545.45	-85.79	-987.91	BTU/lb
Internal Energy	-17716.38	-13139.19	-18287.67	BTU/lb-mol
Internal Energy (Mass)	-551.44	-92.52	-993.19	BTU/lb
Entropy	-0.77	-0.09	-1.43	BTU/lb °F
Heat Capacity (Cp)	0.79	0.54	1.02	BTU/lb °F
Heat Capacity (Cv)	0.60	0.50	0.69	BTU/lb °F
Kappa (Cp/Cv)	1.32	1.09	1.48	-
JT Coefficient		-0.0063	-0.0028	°F/psi
Velocity of Sound		3605.05	10391.20	ft/s
Viscosity		0.6601	0.4369	сР
Thermal Conductivity		0.06	0.39	BTU/(hr ft °F)
Interfacial Tension		34.40	34.40	dyn/cm

Table 7-9: Properties of n- $C_{10}H_{22}$ -brine mixture at 158°F and 1500psi calculated using PREOS.

Table 7-10: Properties of  $n-C_{10}H_{22}$ -brine mixture at 158°F and 1500psi calculated using PREOS.

	Total mole %	Mole % in gas phase	Mole % in aqueous phase	fugacity in gas phase	fugacity in aqueous phase
H2O	88.073	0.222	99.038	4.38E+00	4.38E+00
NaCl	0.841	0.000	0.945	-	-
CaCl <sub>2</sub>	0.015	0.000	0.017	-	-
n-C <sub>10</sub> H <sub>22</sub>	11.072	99.778	0.000	8.46E-01	8.46E-01

	Mole % in	Mole % in	Fugacity	Fugacity coef.	Molar GFE	Molar GFE
	oil phase	aqueous phase	coef. in oil	in Aqueous	in oil	in aqueous
H2O	0.222	99.038	1.32E+00	2.98E-03	-2.6959	-1.1907
NaCl	0.000	0.945	-	-	-	-
CaCl <sub>2</sub>	0.000	0.017	-	-	-	-
n-C <sub>10</sub> H <sub>22</sub>	99.778	0.000	5.65E-04	-	-2.8483	-
Total	100.00	100.00	-	-	-2.8510	-1.1907

Table 7-11: Molar GFE calculations for n-C<sub>10</sub>H<sub>22</sub>-brine mixture at 158°F and 1500 psi.

The calculated molar GFEs are now used in conjunction with measured relative permeability endpoints to derive a GFE-Endpoint curve as depicted in Fig. 7-4. This curve has a monotonic behavior and all endpoints corresponding to GFEs between the reference values can be estimated by linear interpolation.



Figure 7-4: Molar GFE-Endpoint curve using CO<sub>2</sub>, N<sub>2</sub> and nC<sub>10</sub> values as reference points.



Figure 7-5: Relative permeability endpoints as a function of phase densities.

Fig. 7-5 shows a plot of endpoint as a function of phase density using  $CO_2$ ,  $N_2$  and  $nC_{10}$  values as reference. The non-monotonicity of this curve can be attributed to the behavior of  $CO_2$  in super-critical region. As result, in this case, molar GFE is preferred to be used as the measure of composition in order to calculate relative permeability parameters (Fig. 7-4).

### 7.3 SUMMARY

- Steady state relative permeabilities of gas and water in two-phase CO<sub>2</sub>-brine and N<sub>2</sub>-brine displacements have been measured under rigorous experimental conditions on Berea sandstone core.
- The measurements show a noticeable shift in the gas relative permeability between CO<sub>2</sub> and N<sub>2</sub> flooding.
- Phase behavior analysis showed negligible solubility of N<sub>2</sub> in water at 104°F and 1835psi while CO<sub>2</sub> is 2.5 percent of the aqueous phase at the same condition. Molar GFEs were then calculated for both aqueous and gas phases based computed compositions.
- The resulted molar GFEs were combined with measured CO<sub>2</sub>, N<sub>2</sub> and nC<sub>10</sub> data to create a molar GFE-Endpoint curve. This curve has a monotonic behavior and can be used to find the relative permeability parameters by linear interpolation between reference values.
- A density-endpoint curve was also generated using CO<sub>2</sub>, N<sub>2</sub> and nC<sub>10</sub> endpoints a reference. However, due to the non-monotonic behavior of this curve, it is suggested to use GFE as the measure of composition in order to estimate the relative permeability parameters.

# **Chapter 8: Simulation Results**

The robustness of the new relative permeability and capillary pressure models is demonstrated in this chapter by presenting the results of numerical simulations designed to illustrate the effects of compositional changes. The test cases cover a wide range of applications including solvent and miscible gas flooding, miscible/immiscible WAG processes and well stimulation processes using solvents to remove condensate and/or water blocks in both conventional and unconventional formations. The detailed results of all test cases are available in Appendix A.

#### **8.1 SIMULATOR INFORMATION**

The new models were implemented in UTCOMP, a compositional equation of state simulator developed at University of Texas (Chang 1990, Bang 2007). This simulator can solve up to four-phase flow problems and has a three-phase flash calculation module.

UTCOMP makes use of two different phase tracking options. In the first method, a user defined reference component is considered as the tracking reference and its mole fractions in all phases are calculated in every time step. The mole fractions are then compared with the previous time steps to find the new time step labels. The criterion is to minimize the change in mole fraction of the reference component during the two time steps (Perschke 1988). The second approach does not need a reference phase and uses molar GFEs to minimize the change in two subsequent time steps.

#### 8.2 APPLYING EXPERIMENTAL MEASUREMENTS IN THREE-PHASE FLOW MODELLING

In the previous chapter, a GFE-endpoint curve was derived based on two-phase CO2/bine, N2/brine and  $n-C_{10}H_{22}$ /brine relative permeability measurements. In this section, the results are used for a 1D field-scale three-phase simulation. The GFE model is applied in the

simulation to account for the effect of composition on relative permeability and overall fluid displacement.

A 1000 feet long oil reservoir initially in two-phase oil-gas condition is assumed. To be consistent with the experimental conditions, reservoir pressure is 1835 psi and the reservoir temperature is 104 °F. The initial oil consists of 80% n- $C_{10}H_{22}$  plus 20% of  $C_1$ . Pure  $N_2$  gas at 1850 psi is injected into the reservoir for 100 days and oil is produced at 1800 psi. The  $N_2$  is not miscible with the oil at this pressure. The injection and production pressures were selected close to each other to minimize the effect of pressure changes on GFE. The reference conditions for relative permeability endpoints are based on the data shown in Fig. 7-4. However, due to a change in reference temperature from 104 °F in lab conditions to 60 °F in the simulator, there are positive shifts in the GFE values (Look at Eq. 3-2). The other reference values, EOS parameters and results of simulation after 50 days are presented in the following tables and figures. In this case, capillary pressure is neglected as the main focus is on compositional effect.

Table 8-1: PREOS parameters, CO<sub>2</sub>/N<sub>2</sub> flooding.

Component	Tc (F)	Pc (psi)	Vc (ft <sup>3</sup> /mole)	Acentric factor (AC)	MW
CO <sub>2</sub>	304.2	72.8	1.51	0.225	44.01
N <sub>2</sub>	-232.5	492.3	1.44	0.04	28.01
CH <sub>4</sub>	-116.59	667	1.59	0.008	16.043
$n-C_{10}H_{22}$	652.0	305	9.66	0.27504	86.0

Table 8-2 Binary interaction coefficients, CO<sub>2</sub>/N<sub>2</sub> flooding.

Component	$N_2$	$CO_2$	$CH_4$	$n-C_{10}H_{22}$
$N_2$				
CO <sub>2</sub>	-0.017			
CH <sub>4</sub>	0.0311	0.120		
n-C <sub>10</sub> H <sub>22</sub>	0.112	0.114	0.042	

	kr_end	Residual Saturation	Exponent	b	Trapping parameter (T)	GFE/RT
$n-C_{10}H_{22}$	0.86	0.25	3	1	20,000	-1.64
CO <sub>2</sub>	0.69	0.15	2	0	30,000	6.81
N <sub>2</sub>	0.56	0.15	2	0	30,000	7.49

Table 8-3: Reference values,  $CO_2/N_2$  flooding.



Figure 8-1: Relative permeabilities at reference condition,  $CO_2/N_2$  flooding.

Width (X Direction)	1000 ft		
Length (Y Direction)	20 ft		
Thickness (Z Direction)	20 ft		
Grid (X, Y, Z)	$1 \times 50 \times 1$		
Depth (to Reservoir Top)	4100 ft		
Horizontal Permeability	137.9 md		
Initial Reservoir Pressure	1835 psi		
Temperature	104 °F		
Porosity	27.9 %		
Longitudinal Dispersivity	$0 \text{ ft}^2/\text{day}$		
Transverse Dispersivity	$0 \text{ ft}^2/\text{day}$		
Formation Compressibility	5.0x10 <sup>-6</sup> psi <sup>-1</sup>		
Water Compressibility	3.3x10 <sup>-6</sup> psi <sup>-1</sup>		
Water Molar Density	3.467 lb-mole/ft <sup>3</sup>		
Water Viscosity	0.7 cp		
Residual Water Saturation (S <sub>1r</sub> )	25%		
Initial water Saturation	25%		
kr_end for Water	0.1		
<b>Injection Pressure</b>	1850 psi		
Bottom hole Pressure	1800 psi		

Table 8-4: Simulation input parameters,  $CO_2/N_2$  flooding.



Figure 8-2: Overall concentration of  $N_2$  after 100 days of  $N_2$  flooding.



Figure 8-3: Saturations after 100 days of N<sub>2</sub> flooding.



Figure 8-4: Molar GFEs after 100 days of  $N_2$  flooding.



Figure 8-5: Relative permeability endpoints after 100 days of N<sub>2</sub> flooding.



Figure 8-6: Relative permeabilities after 100 days of N<sub>2</sub> flooding.

Fig. 8-3 shows oil and gas saturation profiles in the 1D reservoir during the immiscible  $N_2$  flooding. Molar GFEs are depicted in Fig. 8-4. The relative permeability endpoints interpolated between reference values are shown in Fig. 8-5. Note that there is a precise agreement between the values shown in these plots and the reference numbers given in Table 8-1. Thus the trapping number had no effect in this case. Other relative permeability parameters and residual saturations are also calculated in the same way. All these parameters are then used in Eq. (3-1) to calculate the relative permeability as a function of both composition and saturation (Fig. 8-6).

In the next step, just for the sake of this example and to demonstrate the robustness of the GFE model in capturing the effect of composition on relative permeability, the process is followed by a miscible  $CO_2$  flood. Pure  $CO_2$  is injected at 1850 psi. The results after 100 days of  $CO_2$  flooding are shown below:



Figure 8-7: Overall concentration of N<sub>2</sub> (up) and CO<sub>2</sub> (down) after 100 days of CO2<sub>2</sub> flooding (200 days overall).



Figure 8-8: Saturations after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-9: Molar GFEs after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-10: Rel-perm endpoints after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-11: Relative permeabilities after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-12: Mass densities after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-13: Oil trapping number after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-14: Overall mole fractions after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-15: Mole fractions in oil after 100 days of CO<sub>2</sub> flooding (200 days overall).



Figure 8-16: Mole fractions in gas after 100 days of CO<sub>2</sub> flooding (200 days overall).

As the CO2 moves through the reservoir, the remaining oil is completely dissolved into the gas phase and the residual oil saturation goes to zero (Fig. 8-8). The miscibility of the  $CO_2$ with the oil can be seen in Fig. 8-9 in which the oil and gas molar GFEs approach to each other in the near critical region. This behavior is then directly inherited by all relative permeability parameters that are interpolated by GFE and consequently, ensures the compositional consistency in the critical region. One example of this is presented in Fig. 8-10 for relative permeability endpoint values. Comparing this graph with Table 8-1 reference values clearly shows the effect of compositional on endpoint parameters. The relative permeabilities are shown in Fig. 8-11.

The oil phase trapping number can increase by several orders of magnitude in the critical region as illustrated in Fig. 8-12. However, the peak value is still less that the critical trapping number value so there was no effect on the relative permeability calculations. This is attributed

to the dominant effect of mass transfer between the phases (Eqs. 5-5 to 5-7). Mole fractions are shown in Figs. 8-14 to 8-16.

#### 8.3 MISCIBLE GAS FLOODING IN 3-COMPONENT MIXTURE

In chapter 3, non-monotonic GFE calculations and its effect on the relative permeability were illustrated. The same three-component mixture example (example 4.3.2) is used here to illustrate how this non-monotonic behavior can affect the simulation results.

In this simulation example,  $CO_2$  is injected into a one-dimensional oil reservoir with free gas and residual water saturation. The initial overall hydrocarbon composition consists of 50 mole% CH<sub>4</sub> and 50 mole% FC<sub>6</sub>. Fig. 8-17 shows the composition route of the oil phase on a ternary diagram at 260 F and 1960 psi. In order to retain the shape of the two-phase envelope, injection and production pressures are kept close to the initial pressure.



Figure 8-17: Ternary diagram showing GFE contours at 260 F and 1960 psi.
The EOS parameters are shown in Tables 8-5 and 8-6. The UTCOMP simulation input parameters are shown in Table 8-8. For this miscible case, capillary pressure is neglected. The simulation results after 125 days are presented in Figs. 8-19 to 8-24.

Component	Tc (K)	Pc (bar)	Vc (ft <sup>3</sup> /mole)	Acentric factor (AC)	MW
$CO_2$	304.2	72.8	1.51	0.225	44.01
CH <sub>4</sub>	190.6	45.4	1.59	0.008	16.043
FC <sub>6</sub>	507.5	32.46	5.93	0.27504	86.0

Table 8-5: EOS parameters, miscible flooding.

Table 8-6: Binary interaction coefficients, miscible flooding.

Component	CO <sub>2</sub>	$CH_4$	$FC_6$
CO <sub>2</sub>	0		
CH <sub>4</sub>	0.105	0	
FC <sub>6</sub>	0.115	0.025	0

Table 8-7: Reference values, miscible flooding.

Phase	kr_end	Residual Saturation	Exponent	Trapping parameter (T)	GFE/RT
Oil	0.3	0.3	3	10,000	2.93
Gas	0.7	0.05	2.0	40,000	4.33



Figure 8-18: Relative permeabilities at reference condition, miscible flooding.

1000 ft
20 ft
20 ft
$1 \times 50 \times 1$
4100 ft
137.9 md
1750 psi
260 °F
27.9 %
$0 \text{ ft}^2/\text{day}$
$0 \text{ ft}^2/\text{day}$
$5.0 \mathrm{x} 10^{-6} \mathrm{psi}^{-1}$
$3.3 \times 10^{-6} \text{ psi}^{-1}$
3.467 lb-mole/ft <sup>3</sup>
0.7 cp
25%
25%
0.1
2000 psi
1950 psi

Table 8-8: Simulation input parameters, miscible flooding.



Figure 8-19: Oil and gas saturations after 125 days.



Figure 8-20: Oil and gas molar GFEs after 125 days.



Figure 8-21: Endpoint Oil and gas relative permeability values at 125 days.



Figure 8-22: Oil and gas relative permeabilities after 125 days.



Figure 8-23: Oil trapping number after 125 days.



Figure 8-24: Oil recovery.

Fig. 8-3 shows the injected gas completely displaces the oil. This implies that the residual saturations in this case are controlled by mass transfer between the phases rather than by hysteresis or trapping number effects. Fig. 8-4 shows the GFEs of the oil and gas are identical at the critical point as they should be. A portion of the oil GFE curve shows a very small non-monotonic behavior that has been marked with filled circles. Figs. 8-5 and 8-6 show that the calculated relative permeability values interpolated using GFE are continuous. In Fig. 8-7, oil trapping number increases by several orders of magnitude in the front of the displacement. This change is mainly due to the significant reduction of interfacial tension between oil and gas in near critical region. Fig. 8-8 shows the oil recovery calculated from the volume of cumulative produced hydrocarbon components at reservoir condition divided by the initial oil in place.

### **8.4 CO<sub>2</sub> EOR**

The simulation of  $CO_2$  injection for enhanced oil recovery can be highly challenging since the CO2 can form three phases with the hydrocarbons and result in three or four phase flow counting the aqueous phase. In this example, CO2 tertiary oil recovery in a 2D vertical crosssection of a reservoir is simulated (Lim 1993). The following tables present reservoir and fluid data and also the reference conditions. In this example, capillary pressure effect is neglected.

Component	Fraction
<i>CO</i> <sub>2</sub>	0.0000
<i>C</i> <sub>1</sub>	0.3056
C <sub>2-3</sub>	0.2027
C <sub>4-6</sub>	0.1589
$C_{7-15}$	0.2327
<i>C</i> <sub>16+</sub>	0.1001

Table 8-9: Initial oil mole fractions, CO<sub>2</sub> EOR.

Comp. /Prop.	Tc (K)	Pc (bar)	Vc (ft <sup>3</sup> /mole)	AC	MW
CO <sub>2</sub>	547.6	1069.9	1.506	0.225	44.01
<b>C</b> <sub>1</sub>	343.1	667.2	1.586	0.008	16.04
C <sub>2-3</sub>	612.0	658.6	2.844	0.127	36.27
C <sub>4-6</sub>	835.1	487.5	4.993	0.240	70.42
C <sub>7-15</sub>	1086.4	329.4	11.500	0.609	137.84
C <sub>16+</sub>	1444.9	258.8	18.200	1.042	317.90

Table 8-10: EOS parameters, CO<sub>2</sub> EOR.

Table 8-11: Binary interaction coefficients, CO<sub>2</sub> EOR.

	$CO_2$	$C_1$	C <sub>2-3</sub>	C <sub>4-6</sub>	C <sub>7-15</sub>	C <sub>16+</sub>
$CO_2$	0					
C <sub>1</sub>	0.094	0				
C <sub>2-3</sub>	0.094	0	0			
C <sub>4-6</sub>	0.094	0	0	0		
C <sub>7-15</sub>	0.095	0	0	0	0	
C <sub>16+</sub>	0.095	0	0	0	0	0

Table 8-12: Reference values, CO<sub>2</sub> EOR.

	kr_end	Residual Saturation	Exponent	Trapping parameter (T)	GFE/RT
Oil	0.5	0.25	3	20,000	-1.64
Gas	0.9	0.1	2	30,000	4.94
Second liquid	0.7	0.15	2.5	50,000	6.51



Figure 8-25: Reference relative permeability curves at low trapping number, CO<sub>2</sub> EOR.

Width (X Direction)	1000 ft
Length (Y Direction)	50 ft
Thickness (Z Direction)	55 ft
Grid (X, Y, Z)	50 x 1 x 11
Depth (to Reservoir Top)	4100 ft
Permeability X	137.9 md
Permeability Z	5 md
Initial Reservoir Pressure	1750 psi
Temperature	90 °F
Porosity	27.9 %
Longitudinal Dispersivity	$3.3 \text{ ft}^2/\text{day}$
Transverse Dispersivity	$0.33 \text{ ft}^2/\text{day}$
Formation Compressibility	$5.0 \times 10^{-6} \text{ psi}^{-1}$
Water Compressibility	$3.3 \times 10^{-6} \text{ psi}^{-1}$
Water Molar Density	3.467 lb-mole/ft <sup>3</sup>
Water Viscosity	0.7 cp
Residual Water Saturation (S <sub>1r</sub> )	25%
Initial water Saturation	40%
Kr_end for Water	0.2
Injection Pressure	1800 psi
Bottom hole Pressure	1000 psi

Table 8-13: Simulation input parameters, CO<sub>2</sub> EOR.



Figure 8-26: P-T diagram of initial oil, created by PVTSim Nova.

The simulation results after 300 days of  $CO_2$  injection are presented below. Fig. 8-27 shows the contours of  $CO_2$  with and without trapping number modeled. Fig. 8-28 compares the oil and second liquid saturations in layer 5 (depth=4124 feet) and illustrates how trapping number can change the predicted recovery efficiency.



Figure 8-27: Front of CO<sub>2</sub> without (up) and with (down) trapping number effect.



Figure 8-28: Oil Saturation in layer 5 after 300 days.



Figure 8-29: Trapping number of oil phase in layer 5 at 300 days.

Note that the residual saturations in Fig. 8-28 are not affected by trapping number. This means that the residual saturations are mainly controlled by mass transfer mechanism. The following figures show contours of saturations and relative permeability after 300 days considering trapping number effect. At miscibility regions, there are at least oil and second liquid hydrocarbon phases but there is also a possibility for existence of a gas phase. The gas phase mainly forms around the production well, but it is almost immobile at low gas saturations.



Figure 8-30: Oil saturation after 300 days.



Figure 8-31: Gas saturation after 300 days.



Figure 8-32: Second liquid saturation after 300 days.



Figure 8-33: Oil relative permeability after 300 days.



Figure 8-34: Gas relative permeability after 300 days.



Figure 8-35: Second liquid relative permeability after 300 days.

Plots of molar GFE, saturation and relative permeability in layer 5 at 300 days are presented next.



Figure 8-36: Molar GFEs in layer 5 (depth=4124) at 300 days.



Figure 8-37: Saturations and Relative Permeabilities in layer 5 (depth=4124) after 300 days.

The GFE values become close to each other near the miscibility region but there is no non-monotonic behavior for GFE in the hydrocarbon phases. So this is a good example of how the proposed relative permeability model interpolates between the reference values to calculate the relative permeability parameters.

## 8.5 CO<sub>2</sub>-NGL SOLVENT EOR

In this simulation example, a 7 component  $CO_2$ -NGL solvent is injected and mixes with 12 hydrocarbon components initially in the reservoir. The complexity of this problem demonstrates the robustness of the proposed GFE relative permeability model.

The injected solvent and initial oil compositions are given in Table 8-14 and 8-18. Figure 8-39 is a composition-pressure diagram for mixtures of the solvent and oil at reservoir temperature. This diagram demonstrates that the solvent is in a single phase region at 1800 psi injection pressure and the reservoir fluid can split into two or three hydrocarbon phases as the solvent mixes with the initial oil. In this example, capillary pressure is neglected.

Component	Fraction
<i>CO</i> <sub>2</sub>	0.815
<i>C</i> <sub>3</sub>	0.0043
<i>C</i> <sub>2</sub>	0.038
$nC_4$	0.0798
$nC_5$	0.0522
nC <sub>6</sub>	0.0267
<i>nC</i> <sub>7-9</sub>	0.022

Table 8-14: Solvent mole fractions, CO<sub>2</sub>-NGL solvent.

<i>CO</i> <sub>2</sub>	0.000436
<i>C</i> <sub>1</sub>	0.272149
<i>C</i> <sub>2</sub>	0.004128
<i>C</i> <sub>3</sub>	0.010484
$nC_4$	0.02123
$nC_5$	0.02002
<i>C</i> <sub>6</sub>	0.022566
C <sub>7-9</sub>	0.098746
C <sub>10-13</sub>	0.100533
<i>C</i> <sub>14-19</sub>	0.145138
C <sub>20-35</sub>	0.164159
C <sub>36</sub> +	0.140411

Table 8-15: Initial oil mole fractions, CO<sub>2</sub>-NGL solvent.

Table 8-16: EOS parameters, CO<sub>2</sub>-NGL solvent.

Comp. /Prop.	Tc (°R)	Pc (psi)	Vc (ft <sup>3</sup> /mole)	AC	MW
CO <sub>2</sub>	547.6	1069.9	0.416	0.225	44.01
C <sub>1</sub>	343.1	667.2	1.602	00.013	16.04
$C_2$	549.8	707.8	2.451	0.099	30.07
C <sub>3</sub>	665.7	616.3	3.300	0.152	44.10
nC <sub>4</sub>	765.3	550.7	4.088	0.201	58.12
nC <sub>5</sub>	845.4	488.6	4.946	0.254	72.15
C <sub>6</sub>	923.0	483.8	5.294	0.258	84.00
C <sub>7-9</sub>	1040.3	415.4	8.553	0.317	145.16
C <sub>10-13</sub>	1199.6	255.4	13.110	0.256	223.26
C <sub>14-19</sub>	1346.6	203.9	23.070	0.577	353.51
C <sub>20-35</sub>	1532.74	158.0	33.235	0.766	554.55
C <sub>36+</sub>	1967.3	94.8	83.571	1.131	1052.00

Comp. /Prop.	Tc (°R)	Pc (psi)	Vc (ft <sup>3</sup> /mole)	AC	MW
$CO_2$	547.6	1069.9	0.416	0.225	44.01
$C_1$	343.1	667.2	1.602	00.013	16.04
$C_2$	549.8	707.8	2.451	0.099	30.07
C <sub>3</sub>	665.7	616.3	3.300	0.152	44.10
$nC_4$	765.3	550.7	4.088	0.201	58.12
nC <sub>5</sub>	845.4	488.6	4.946	0.254	72.15
$C_6$	923.0	483.8	5.294	0.258	84.00
C <sub>7-9</sub>	1040.3	415.4	8.553	0.317	145.16
C <sub>10-13</sub>	1199.6	255.4	13.110	0.256	223.26
C <sub>14-19</sub>	1346.6	203.9	23.070	0.577	353.51
C <sub>20-35</sub>	1532.74	158.0	33.235	0.766	554.55
C <sub>36+</sub>	1967.3	94.8	83.571	1.131	1052.00

Table 8-17: EOS parameters,  $CO_2$ -NGL solvent.

Table 8-18: Binary interaction coefficients, CO<sub>2</sub>-NGL solvent.

	CO <sub>2</sub>	C <sub>1</sub>	C <sub>2</sub>	C <sub>3</sub>	nC <sub>4</sub>	nC <sub>5</sub>	C <sub>6</sub>	C <sub>7-9</sub>	C <sub>10-13</sub>	C <sub>14-19</sub>	C <sub>20-35</sub>	C <sub>36+</sub>
CO <sub>2</sub>	0.00000											
C <sub>1</sub>	0.07162	0.00000										
C <sub>2</sub>	0.09399	0.00519	0.00000									
C <sub>3</sub>	0.09759	0.01677	0.00394	0.00000								
nC <sub>4</sub>	0.093937	0.03675	0.01226	0.00000	0.00000							
nC <sub>5</sub>	0.09034	0.04421	0.02316	0.00001	0.00000	0.00000						
C <sub>6</sub>	0.07454	0.00000	0.03071	0.01065	0.00026	0.00003	0.00000					
C <sub>7-9</sub>	0.09191	0.00001	0.05030	0.02209	0.00083	0.00045	0.00001	0.00000				
C <sub>10-</sub> 13	0.09863	0.00001	0.00497	0.00259	0.00205	0.00122	0.00001	0.00001	0.00000			
C <sub>14-</sub> 19	0.11636	0.16940	0.04511	0.02952	.01012	0.01001	0.00001	0.00001	0.00000	0.00000		
C <sub>20-</sub> 35	0.11636	0.17835	0.06547	0.05574	0.02093	0.01921	0.00002	0.00002	0.00000	0.00000	0.00000	
C <sub>36+</sub>	0.16348	0.18222	0.13363	.12456	0.05379	0.04953	0.00004	0.00002	0.00001	0.00001	0.00002	0.00000



Figure 8-38: Phase envelope of initial oil created by PVTSim Nova, CO<sub>2</sub>-NGL solvent.



Figure 8-39: Pressure-composition diagram for CO2-LNG mixture.

At the initial condition, the reservoir fluid is a liquid at the initial pressure of 1750 psi. A second liquid forms around the injection well once the solvent fraction exceeds an overall mole fraction of 0.55. A gas phase also appears near the production well and also at the front of the injected  $CO_2$  where the miscibility takes place. The simulations were performed for both one and two dimensional reservoirs.

# 8.5.1 1D Reservoir

The reservoir information and reference conditions and also the simulation results are shown in the following tables and graphs.

	kr_end	Residual Saturation	Exponent	b	Trapping parameter (T)	GFE/RT
Oil	0.5	0.3	2.0	1	20,000	-9.55
Gas	0.9	0.05	3.0	.5	50,000	5.47
Second liquid	0.7	0.2	2.0	0	30,000	6.94

Table 8-19: Reference values, CO<sub>2</sub>-NGL solvent.



Figure 8-40: Relative permeabilities at reference condition, CO<sub>2</sub>-NGL solvent.

1000 ft
20 ft
20 ft
50 x 1 x 1
4100 ft
137.9 md
1750 psi
86 °F
27.9 %
$0 \text{ ft}^2/\text{day}$
0 It / day
$\frac{0 \text{ ft}^2/\text{day}}{0 \text{ ft}^2/\text{day}}$
$\frac{0 \text{ ft}^2/\text{day}}{5.0 \text{x} 10^{-6} \text{ psi}^{-1}}$
$\frac{0 \text{ ft}^2/\text{day}}{5.0 \text{x} 10^{-6} \text{ psi}^{-1}}$ $3.3 \text{x} 10^{-6} \text{ psi}^{-1}$
$\frac{0 \text{ ft}^{2}/\text{day}}{5.0 \text{x} 10^{-6} \text{ psi}^{-1}}$ $3.3 \text{x} 10^{-6} \text{ psi}^{-1}$ $3.467 \text{ lb-mole/ft}^{3}$
$     \begin{array}{r}       0 \text{ ft}^{2}/\text{day} \\       5.0x10^{-6} \text{ psi}^{-1} \\       3.3x10^{-6} \text{ psi}^{-1} \\       3.467 \text{ lb-mole/ft}^{3} \\       0.7 \text{ cp} \\     \end{array} $
$\begin{array}{r} 0 \text{ ft}^{2}/\text{day} \\ \hline 0 \text{ ft}^{2}/\text{day} \\ \hline 5.0 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.3 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.467 \text{ lb-mole/ft}^{3} \\ \hline 0.7 \text{ cp} \\ \hline 25\% \end{array}$
$\begin{array}{r} 0 \text{ ft}^{2}/\text{day} \\ \hline 0 \text{ ft}^{2}/\text{day} \\ \hline 5.0 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.3 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.467 \text{ lb-mole/ft}^{3} \\ \hline 0.7 \text{ cp} \\ \hline 25\% \\ \hline 40\% \end{array}$
$\begin{array}{r} 0 \text{ ft}^{2}/\text{day} \\ \hline 0 \text{ ft}^{2}/\text{day} \\ \hline 5.0 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.3 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.467 \text{ lb-mole/ft}^{3} \\ \hline 0.7 \text{ cp} \\ \hline 25\% \\ \hline 40\% \\ \hline 0.1 \end{array}$
$\begin{array}{r} 0 \text{ ft}^{2}/\text{day} \\ \hline 0 \text{ ft}^{2}/\text{day} \\ \hline 5.0 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.3 \text{x} 10^{-6} \text{ psi}^{-1} \\ \hline 3.467 \text{ lb-mole/ft}^{3} \\ \hline 0.7 \text{ cp} \\ \hline 25\% \\ \hline 40\% \\ \hline 0.1 \\ \hline 1800 \text{ psi} \end{array}$

Table 8-20: Simulation input parameters, CO<sub>2</sub>-NGL solvent.



Figure 8-41: Effect of trapping number on oil saturation (120 Days).



Figure 8-42: Oil phase trapping number across the1D reservoir (120 Days).



Figure 8-43: Molar GFEs after 120 days, 1D.



Figure 8-44: Saturation and relative permeability after 120 days, 1D.



Figure 8-45: Oil recovery, 1D.

Figures 5-41 and 5-42 show the oil phase trapping number variation across the 1D reservoir after 120 days and its effect on oil saturation. The gas saturation is lower than its residual value so it is immobile in the entire domain. By looking at the GFE plots and comparing it with saturation and oil trapping number curves, it can be seen that the miscibility condition happens at the front of the injected CO2 and the GFEs of oil and second liquid are very close to each other leading to the same relative permeability endpoint values.

The new relative permeability model can successfully handle the miscibility condition assuring a continuous curve for relative permeability. The details of the above graphs and compositions of the oil and second liquid phases for 1D case are available in appendix A.

#### 8.5.2 Homogeneous 2D Reservoir

The previous 1D example is extended to a 2D homogeneous domain. The contours of saturations,  $CO_2$  overall mole fraction, saturations and permeability after 1.5 PV or 330 days are shown below:



Figure 8-46: Overall mole fraction of CO2 after 1.5 PV (330 Day).



Figure 8-47: Water saturation after 1.5 PV (330 Day).



Figure 8-48: Oil saturation after 1.5 PV (330 Day).



Figure 8-49: Gas saturation after 1.5 PV (330 Day).



Figure 8-50: Second liquid saturation after 1.5 PV (330 Day).



Figure 8-51: Oil relative permeability after 1.5 PV (330 Day).



Figure 8-52: Gas relative permeability after 1.5 PV (330 Day).



Figure 8-53: Second liquid relative permeability after 1.5 PV (330 Day).

The molar GFEs, saturations and relative permeabilities for a selected layer (layer 7) after 1.5 PV or 330 days are shown below:



Figure 8-54: GFEs after 1.5 PV in layer 7 (330 Day).



Figure 8-55: Saturation and relative permeability after 1.5 PV (330 Day) in layer 7.

As the above figures show, the saturation and GFE distributions in the 2D reservoir follow a complicated pattern depending on reservoir and fluids properties. However, the flexibility of new model makes the relative permeability calculations straightforward.

# 8.5.3 Heterogeneous 2D Reservoir

The simulations were repeated for a heterogeneous reservoir. The input file of this test case is available in Appendix B. The results are presented below:



Figure 8-56: Formation porosity for heterogeneous reservoir.



Figure 8-57: Permeability in horizontal direction  $(k_X)$  for heterogeneous reservoir.



Figure 8-58: Water saturation after 0.25 PV (125 Day).



Figure 8-59: Oil saturation after 0.25 PV (125 Day).



Figure 8-60: Gas saturation after 0.25 PV (125 Day).



Figure 8-61: Second liquid saturation after 0.25 PV (125 Day).



Figure 8-62: Oil relative permeability after 0.25 PV (125 Day).



Figure 8-63: Gas relative permeability after 0.25 PV (125 Day).



Figure 8-64: Second liquid relative permeability after 0.25 PV (125 Days).

More detailed results for layer 10 are shown below. The exact values are also available in Appendix A.



Figure 8-65: Saturations and relative permeability after 0.25 PV for layer 10 (125 Days).

These results illustrate how the heterogeneity of the reservoir affects the results. Continuity in the relative permeability calculations using the new model becomes even more important with heterogeneity.

## 8.6 MULTI-CYCLE IMMISCIBLE WAG

Water Alternating Gas (WAG) is an EOR method to improve volumetric sweep efficiency. WAG methods can be miscible or immiscible displacements. However, it is sometimes difficult to distinguish between miscibility conditions for WAG injections. In many cases, multi-contact gas/oil miscibility may have been obtained and much uncertainty remains about the actual displacement process (Christensen et al 2001). Hence, compositional effects should always be considered for more accurate prediction of this type of recovery process.

Hysteresis in multi-cycle WAG displacement is important due to changes in saturation directions. Integrating this effect with compositional dependency requires robust historic relative permeability and capillary pressure models to reflect all aspects of the involved physics. In this example adapted from Pudugramam (2013), the developed three-phase compositional relative permeability and capillary pressure models are used for simulation of a field-scale immiscible WAG process. Each cycle starts with 15 days CO<sub>2</sub> gas flooding followed by 15 days water injection. The following tables and charts show the reservoir and flow characteristics.

Component	Fraction
<i>CO</i> <sub>2</sub>	0.0114
<i>C</i> <sub>1</sub>	0.1454
C <sub>2-3</sub>	0.1751
$C_{4-6}$	0.125
C <sub>7-9</sub>	0.1261
C <sub>10-13</sub>	0.1398
<i>C</i> <sub>14-19</sub>	0.1237
C <sub>20</sub> +	0.1535

Table 8-21: Initial oil mole fractions, WAG.

Comp.	$Tc (^{0}R)$	Pc (psi)	Vc (ft <sup>3</sup> /mole)	AC	MW
<i>CO</i> <sub>2</sub>	547.56	1069.87	1.603	0.225	44.01
<i>C</i> <sub>1</sub>	319.44	631.54	1.795	0.0145	17.57
C <sub>2-3</sub>	835.84	657	3.452	0.1279	36.51
$C_{4-6}$	1050.45	491.36	5.199	0.2423	69.85
C <sub>7-9</sub>	1196.58	409.01	6.291	0.3533	104.38
<i>C</i> <sub>10-13</sub>	1359.53	310.05	9.33	0.5003	154.13
<i>C</i> <sub>14-19</sub>	1359.53	250.43	16.898	0.6836	222.78
$C_{20^{+}}$	2020.83	187.67	29.737	0.8328	516.41

Table 8-22: EOS parameters, WAG.

Table 8-23: Binary interaction coefficients, WAG.

	CO <sub>2</sub>	C <sub>1</sub>	C <sub>2-3</sub>	C <sub>4-6</sub>	C <sub>7-15</sub>	C <sub>16+</sub>
<i>CO</i> <sub>2</sub>	0					
$C_1$	0.111	0				
C <sub>2-3</sub>	0.12	0	0			
C <sub>4-6</sub>	0.175	0	0	0		
C <sub>7-9</sub>	0.075	0	0	0	0	
<i>C</i> <sub>10-13</sub>	0.05	0	0	0	0	0
<i>C</i> <sub>14-19</sub>	0.07	0	0	0	0	0
$C_{20^{+}}$	0.075	0	0	0	0	0

Table 8-24: Reference values, WAG.

Phase	kr_end	Residual Saturation	Exponent	b	Trapping parameter (T)	GFE/RT
Water	0.7	0.3	3	0.5	1000	
Oil	0.5	0.25	3	1	20,000	-2.7
Gas	0.9	0.35	2	0.5	40,000	7.4

Table 8-25: Capillary pressure parameters, WAG.

Phase	Coil (psi)	$C_{gas}$ (psi)	C <sub>water</sub> (psi)	a <sub>oil</sub>	a <sub>gas</sub>	a <sub>water</sub>
Water-Oil	-2	-	10	2	-	2
Oil-Gas	-1	5	-	2	2	-

Width (X Direction)	2500 ft
Length (Y Direction)	50 ft
Thickness (Z Direction)	400 ft
Grid (X, Y, Z)	50 x 1 x 10
Depth (to Reservoir Top)	4100 ft
Permeability X	500 md
Permeability Z	100 md
Initial Reservoir Pressure	1750 psi
Temperature	90 °F
Porosity	27.9 %
Longitudinal Dispersivity	$3.3 \text{ ft}^2/\text{day}$
Transverse Dispersivity	$0.33 \text{ ft}^2/\text{day}$
Formation Compressibility	5.0x10 <sup>-6</sup> psi <sup>-1</sup>
Water Compressibility	$3.3 \times 10^{-6} \text{ psi}^{-1}$
Water Molar Density	3.467 lb-mole/ft <sup>3</sup>
Water Viscosity	0.7 cp
Initial water Saturation	45%
Injection Pressure	1800 psi
Bottom hole Pressure	1000 psi

Table 8-26: Simulation input parameters, WAG.

In Fig. 8-66 depicts the effect of capillary pressure on the CO2 concentration in the top layer. Fig. 8-67 depicts the gas saturation, residual saturation and relative permeability during three cycles in cell A marked in Fig. 8-70. Fig. 8-68 shows the capillary pressure between oil-water and oil-gas phases in the same cell. Figures 8.70 to 8.78 show saturation contours at the end of three different cycles.



Figure 8-66: Effect of capillary pressure on CO2 concentration in layer 1 after cycle 3 (90 Days).



Figure 8-67: Gas saturation, residual saturation and relative permeability in cell A.



Figure 8-68: Capillary pressure of gas and water in cell A.



Figure 8-69: Oil saturation in cell A.



Figure 8-70: Water saturation after cycle 1 (30 Days).



Figure 8-71: Oil saturation after cycle 1 (30 Days).



Figure 8-72: Gas saturation after cycle 1 (30 Days).



Figure 8-73: Water saturation after cycle 2 (60 Days).



Figure 8-74: Oil saturation after cycle 2 (60 Days).



Figure 8-75: Gas saturation after cycle 2 (60 Days).



Figure 8-76: Water saturation after cycle 3 (90 Days).



Figure 8-77: Oil saturation after cycle 3 (90 Days).



Figure 8-78: Gas saturation after cycle 3 (90 Days).

The effect of hysteresis on residual gas saturation and relative permeability is clearly shown in Fig. 8-67. During the first gas increasing displacement in cycle 1, residual gas saturation is zero. Once the saturation direction is reversed, the gas phase is gradually trapped by water. The same process is repeated during next cycles. The behavior has a significant effect in reducing gas relative permeability. For example, gas relative permeability at a saturation of 0.3 dramatically decreases from 0.8 in cycle 1 to 0.2 and 0.03 in cycles 2 and 3, respectively.

The three-phase capillary pressure values in Fig. 8-68 show a cyclic behavior. During each gas injection period, the oil-water capillary pressure decreases as the normalized water saturation decreases. However, the capillary pressure for gas-oil is mainly controlled by the interfacial tension between the two phases. By continuing gas injection, the mole percent of heavy components in oil increases and consequently, IFT and capillary pressure may increase. The details are shown in Appendix A.

This test case presents a good example of how GFE model can integrate all compositional, hysteresis and capillary pressure effects during a complex multi-cycle process. The simulation ran very fast and smooth and the results appear to be physically correct.
#### 8.7 CHEMICAL WELL STIMULATION FOR GAS CONDENSATE BLOCKAGE REMOVAL

Gas condensate build up around production wells in conventional and unconventional gas reservoirs can have a dramatic effect on production rate as it significantly reduces the gas relative permeability (Pope et al 2000). Injection of dimethyl ether (DME) into a production well has been proposed as an effective method to remove the water and condensate blockages (Ganjdanesh et al. 2016). DME is a solvent that mixes with and displaces both water and condensate under reservoir conditions. However, numerical simulation of this process is very complicated due to the frequent phase flipping or misidentification. Classical relative permeability models fail to solve this problem since they all depend on phase labels. As result, frequent discontinuous jumps in relative permeability values make the simulation process very slow and the numerical results are not consistent with known physics.

The GFE model is proposed for simulation of this complicated process. This model is expected to have a very good performance in solution of this type pf problems with phase identification problem since it is completely label independent and makes use of unconditionally continuous GFE values for relative permeability calculations.

A 1D reservoir with one production/injection well is considered. The size of the reservoir is large enough so it is assumed that the outer boundary remains at constant pressure condition. Before production starts, the reservoir only contains gas and  $H_2O$  or aqueous. The initial hydrocarbon compositions, reservoir and fluid data and reference conditions are presented in tables below (adapted from Ganjdanesh et al. 2016):

Component	Fraction
H <sub>2</sub> 0	0.750000
N <sub>2</sub>	0.000990
C <sub>1</sub>	0.184407
C <sub>2</sub>	0.037875
C <sub>3</sub>	0.013710
$C_4 - C_6$	0.010703
$C_7 - C_{80}$	0.002314

Table 8-27: Initial reservoir fluid mole fractions, DME.

Table 8-28: EOS parameters, DME.

Component	$Tc (^{0}R)$	Pc (psi)	Vc (ft <sup>3</sup> /mole)	AC	MW
H <sub>2</sub> 0	1165.14	3197.85	0.985	0.344	18.015
N <sub>2</sub>	227.16	492.32	1.437	0.040	28.013
C <sub>1</sub>	343.08	667.20	1.590	0.008	16.043
C <sub>2</sub>	549.72	708.35	2.337	0.098	30.070
C <sub>3</sub>	665.64	615.76	3.260	0.152	44.097
$C_4 - C_6$	817.09	501.82	4.784	0.229	66.993
$C_7 - C_{80}$	1322.28	404.14	9.250	0.370	116.800
DME	720.51	789.39	2.851	0.200	46.070

Table 8-29: Binary interaction coefficients, DME.

Component	H <sub>2</sub> O	N <sub>2</sub>	C <sub>1</sub>	C <sub>2</sub>	C <sub>3</sub>	$C_{4} - C_{6}$	$C_7 - C_{80}$	DME
H <sub>2</sub> O	0.0							
N <sub>2</sub>	0.15	0.0						
C <sub>1</sub>	0.49	0.03	0.0					
C <sub>2</sub>	0.49	0.04	0.0	0.0				
C <sub>3</sub>	0.55	0.09	0.0	0.0	0.0			
$C_{4} - C_{6}$	0.45	0.10	0.0	0.0	0.0	0.0		
$C_7 - C_{80}$	0.45	0.10	0.0	0.0	0.0	0.0	0.0	
DME	-0.25	0.10	0.29	0.25	0.25	0.20	0.08	0.0

Phase	kr_end	Residual Saturation	Exponent	b	Trapping parameter (T)	GFE/RT
Oil	0.5	0.3	3.0	1	20,000	1.82
Gas	0.85	0.2	2.0	0	50,000	8.65
Aqueous	0.15	0.25	2.0	0	2,000	2.72

Table 8-30: Reference values, DME.

Table 8-31: Simulation input parameters, DME.

Width (X Direction)	2628 ft
Length (Y Direction)	0.65 to 1836.5 ft
Thickness (Z Direction)	30 ft
Grid (X, Y, Z)	50 x 1 x 1
Depth (to Reservoir Top)	4100 ft
Permeability X	10 md
Initial Reservoir Pressure	2000 psi
Temperature	100 °F
Porosity	16 %
Longitudinal Dispersivity	$0 \text{ ft}^2/\text{day}$
Transverse Dispersivity	$0 \text{ ft}^2/\text{day}$
Formation Compressibility	5.0x10 <sup>-6</sup> psi <sup>-1</sup>
Water Compressibility	$3.3 \times 10^{-6} \text{ psi}^{-1}$
Water Molar Density	3.467 lb-mole/ft <sup>3</sup>
Water Viscosity	0.7 cp
Initial water Saturation	70%
Bottom hole Pressure	1000 psi



Figure 8-79: Phase envelope of initial reservoir fluid, created by PVTSim Nova.



Figure 8-80: Reference relative permeability curves at low trapping number, DME.

During initial production, the condensate builds up around the production well. After 50 days, the production decline is treated by injection of DME solvent for 0.2 days followed by 0.8 days shut in and then injection of  $N_2$  chase gas for 0.2 days. After the treatment, well is put back on production.

In Figs. 8-81 and 8-82, profiles of gas saturation and relative permeability after 50 days of production are shown. These graphs illustrate how the accumulation of gas condensates around the production well can dramatically reduce the gas relative permeability.



Figure 8-81: Saturations after 50 days production.



Figure 8-82: Gas relative permeability after 50 days production.

At this time, DME is injected into the reservoir through the production well in order to remove the condensate blockage and improve the gas productivity. Fig. 8-83 shows the saturations calculated by the simulator after DME flooding as outputted by the simulators. DME completely dissolved the built up condensate and pushed back the reservoir fluid. However, this graph shows a sharp discontinuity between liquid 1 and aqueous phase saturations. Comparing the generated saturation curves with other properties such as density, mole fraction, and viscosity and also with PVTSim results, it can be easily shown that this jump in numerical output is completely non-physical and is caused by a phase flipping during the simulation.



Figure 8-83: Saturations after DME injection as shown in simulation output.

Although the phase flipping can cause problems with post-processing, it should be emphasized that it does not affect relative permeability calculations using the GFE model. The critical point is that the GFE model is completely independent of phase labels as it only uses the molar GFEs to calculate all the relative permeability and capillary pressure parameters. Hence, even in case of phase flipping, the simulation process runs very fast and smooth and the numerical results remain unaffected by the misidentification of the phase labels. This important fact gives a significant advantage to the GFE model for simulation of complex recovery processes with phase identification problems where all label dependent models fail to give physically accurate results and make the numerical solution very slow.

Just for the sake of better understanding about the physical process, the previous saturation curve was corrected to show the correct phase labels as presented in Fig. 8-84.



Figure 8-84: Label corrected saturation curves after DME injection.

Next, the simulation process was continued by injection of  $N_2$  chase gas and then by production through the stimulated well. The results before and after labeling correction are shown in the following figures. Note that the labels in the output were changed to make the results easier to be interpreted correctly. The relative permeability, saturation and composition calculated during the simulation were correct.



Figure 8-85: Saturations after  $N_2$  injection as shown in simulation output.



Figure 8-86: Label corrected Saturation curves after  $N_2$  injection.



Figure 8-87: Relative permeabilities after  $N_2$  injection as shown in simulation output.



Figure 8-88: Label corrected relative permeability curves after N<sub>2</sub> injection.



Figure 8-89: Concentrations after N<sub>2</sub> injection, unaffected by phase flipping.



Figure 8-90: Gas relative permeability before and after DME treatment.



Figure 8-91: Gas production rate.

Fig. 8-90 shows the gas relative permeability just before and 5 days after the DME treatment. DME has successfully removed the water and condensate blockage around the production well and the relative permeability has significantly increased. Once the production is resumed, the gas production rate dramatically increases. However, the gas condensate again forms around the production well. Fig. 8-91 depicts the gas production rate as a function of time. It should be noted that production rate is also independent of phase labels since it only depends on the overall production rate of the components.

This example shows the advantage of the GFE model over classical models in simulation of complicated multi-phase flow problems with phase identification issues. The simulation processes ran very fast and the results show very good agreement with the expected physics.

## **Chapter 9: Summary and Conclusions**

A simple coupled formulation for three-phase relative permeability and capillary pressure has been developed and tested for use in compositional reservoir simulators. The new formulation, for the first time, incorporates hysteresis and compositional consistency for both capillary pressure and relative permeability models. This approach completely prevents phase flipping and misidentification that commonly occur in compositional simulations.

Simulation of three-phase flow is essential for accurate modelling of many oil recovery processes in both conventional and unconventional reservoirs. Some examples are water flooding in the presence of free gas, solvent stimulation of liquid blocking by water and condensate and miscible-gas enhanced oil recovery using water-alternating gas. The inherent complexity of three-phase relative permeability and capillary pressure models compared with two-phase models is due in part from more degrees of freedom in saturation direction and path.

The key principle of the models is identification of phases and all relevant parameters based on molar Gibbs Free Energy (GFE) instead of phase labels. This approach offers significant advantages over conventional three-phase correlations. First, it ensures continuity in the calculated values of the relative permeability and capillary pressure as phases appear or disappear during compositional simulations, including near critical points. Second, relative permeability and capillary pressure parameters are evaluated independent of phase labels and thus are not affected by phase misidentification or flipping. Third, the GFE model can capture the effect of composition on relative permeability parameters.

For two-phase hysteresis, a modification of Land's equation for residual saturations with a better match to experimental data was used in which all phase parameters are interpolated between reference values using GFE. The calculated two-phase residual saturations were then used to predict two-phase relative permeability assuming reversible scanning curves. For threephase flow, two-phase residual saturations were modified to account for saturation path and then applied to calculate three-phase residual saturations and relative permeability. This straightforward modification is in very good agreement with three-phase experimental data. The cycle dependency of relative permeability was also included by modifying a previously developed approach to the GFE model.

The dimensionless trapping number quantifies the balance of viscous and gravitational forces acting on a phase trapped by capillary forces in a pore throat and is the most general parameter to represent the reservoir condition. A general algorithm was developed to integrate three-phase hysteresis with trapping number and GFE interpolation.

A new three-phase capillary pressure model was developed following the same principles used for relative permeability with hysteresis and compositional consistency. The capillary pressure between each two phases is considered as a function of two independent saturations with different coefficients which makes it flexible to be used for any wettability conditions. All phase dependent parameters are interpolated by GFE and the three-phase residual saturations are the same as used in the relative permeability model.

An important part of this research was analyzing experiment data to elucidate the effect of composition on relative permeability parameters. The results of a series of recently completed experiments at University of Texas showed a considerable difference in relative permeability between CO2-brine and N2-brine mixtures in the same core. These results were then integrated with phase behavior calculations and used as an input for numerical simulations. The performance and robustness of the three-phase GFE models were demonstrated by several compositional simulation test cases:

- Applying GFE model in conjunction with the empirically measured GFE-endpoint curve successfully captured the effect of phase composition on relative permeability parameters and simulation results in a very simple and convenient way.
- GFE models ensure an unconditional continuity in relative permeability values. Hence, all simulations in near or super critical region run very fast and smooth without any nonphysical jump or discontinuity in numerical results.

- The trapping number had a significant effect on relative permeability during solvent flooding and miscible-gas injection test cases.
- The new GFE model successfully captured the three-phase hysteresis effects in a multi-cycle WAG example. It was shown that how the residual saturations, relative permeability and capillary pressure between immiscible phases change during subsequent cycles in a very predictable and physically reasonable way.
- Molar GFE is not always a monotonic function of composition. However, the effect of nonmonotonic behavior on relative permeability is far less than the typical uncertainties in the experimental data.
- The UTCOMP compositional simulator makes use of a very robust phase labeling algorithm. However, even in case of phase flipping or misidentification during a simulation, the relative permeability and capillary pressure calculations using GFE model are not affected by the phase flipping.

### **FUTURE WORK**

In this research, we used a set of two-phase gas/brine and oil/brine experimental measurements and presented an empirical relationship between GFE and relative permeability endpoints. However, more two and three-phase experiments with different fluids and mixtures are required to gain a more comprehensive understanding of the effect of composition.. The experiments should also involve mass transfer between the phases in order to maximize the compositional effect and all can be analyzed using the same procedure explained in Chapter 7.

Moreover, although phase misidentification cannot have any effect on the GFE model predication for relative permeability and capillary pressure, it still matters for post-processing purposes (interpretation of the output by the user). In UTCOMP, phase labeling can be done by either reference mole fraction or GFE tracking modules. However, both of these methods have limitations and cannot be used in all circumstances. In order to improve the phase identification procedure, one reasonable idea is to combine these two methods into one algorithm. In this way, mole fraction tracking could be used as the default method but if it fails, then the GFE tracking method could be applied. This idea is not expected to add any computational load since the fugacities are already calculated at each time step for flash calculations in UTCOMP and other compositional simulators.

# **Appendix A: Details of Simulation Results**

This appendix provides the details of results and graphs presented in chapter 8. Following notations were used in all tables:

1: water

2: oil

3: gas

4: second liquid or aqueous

GFE: molar Gibbs free energy

TNUM: Trapping number

S: Saturation

PR: Endpoint

E: Exponent

ENDKRL: Relative permeability endpoint at low trapping number

EXPL: Relative permeability exponent at low trapping number

RSL: Relative permeability exponent at low trapping number

SR: Residual saturation

C: Molar %

CAP: Capillary pressure (psi)

## EXAMPLE 8-2 DATA

After 200 days CO<sub>2</sub> flooding:

X (ft)	GFE_oil	GFE_gas	kro	krg	krend_oil	krend_gas	S_oil	S_gas
10		6.786	0.0687	0.4644		0.69	0	0.7634
30		6.786	0.1119	0.4537		0.69	0	0.7586
50		6.786	0.1440	0.4452		0.69	0	0.7548
70		6.784	0.1547	0.4487		0.69	0	0.7564
90		6.780	0.1498	0.4399		0.69	0	0.7524
110		6.764	0.1469	0.4393		0.691	0	0.7521

130		6.700	0.1433	0.4441		0.692	0	0.7541
150		6.379	0.1375	0.4467		0.699	0	0.7541
170		5.829	0.1321	0.4507		0.71	0	0.7541
190		5.639	0.1306	0.4588		0.714	0	0.7570
210	4.745	6.327	0.1312	0.0319	0.732	0.7	0.416	0.3388
230	3.414	6.500	0.1344	0.0146	0.759	0.696	0.466	0.2888
250	1.521	6.679	0.1400	0.0146	0.797	0.692	0.501	0.2523
270	0.211	7.123	0.1447	0.0146	0.824	0.63	0.516	0.2351
290	-0.165	7.472	0.1479	0.0146	0.832	0.565	0.515	0.2340
310	-0.171	7.497	0.1500	0.0146	0.832	0.561	0.514	0.2351
330	-0.174	7.495	0.1519	0.0146	0.832	0.561	0.512	0.2371
350	-0.176	7.494	0.1534	0.0146	0.832	0.561	0.508	0.2403
370	-0.179	7.493	0.1530	0.0146	0.832	0.561	0.505	0.2434
390	-0.182	7.491	0.1509	0.0146	0.832	0.562	0.504	0.2443
410	-0.185	7.488	0.1483	0.0146	0.832	0.562	0.505	0.2439
430	-0.188	7.484	0.1464	0.0146	0.832	0.563	0.507	0.2420
450	-0.191	7.476	0.1467	0.0146	0.832	0.564	0.510	0.2387
470	-0.194	7.459	0.1486	0.0146	0.832	0.568	0.512	0.2359
490	-0.194	7.418	0.1468	0.0146	0.832	0.575	0.514	0.2341
510	-0.180	7.333	0.0825	0.0146	0.832	0.591	0.515	0.2330
530	-0.142	7.221	0.0295	0.0146	0.831	0.612	0.516	0.2322
550	-0.079	7.103	0.0315	0.0146	0.83	0.634	0.516	0.2319
570	0.005	6.994	0.0370	0.0146	0.828	0.654	0.516	0.2326
590	0.103	6.902	0.0565	0.0146	0.826	0.671	0.514	0.2345
610	0.210	6.829	0.3687	0.0146	0.824	0.685	0.512	0.2366
630	0.320	6.774	0.4676	0.0146	0.822	0.691	0.510	0.2386
650	0.429	6.735	0.4684	0.0146	0.82	0.691	0.509	0.2395
670	0.537	6.712	0.4683	0.0146	0.818	0.692	0.509	0.2394
690	0.639	6.700	0.4682	0.0146	0.815	0.692	0.508	0.2411
710	0.738	6.698	0.4682	0.0195	0.813	0.692	0.464	0.2854
730	0.837	6.705	0.4681	0.0596	0.811	0.692	0.403	0.3466
750	0.928	6.719	0.4681	0.0570	0.81	0.692	0.406	0.3443
770	1.000	6.734	0.4681	0.0501	0.808	0.691	0.413	0.3365
790	1.050	6.747	0.4057	0.0328	0.807	0.691	0.437	0.3124
810	1.073	6.754	0.0687	0.0000	0.807	0.691	0.597	0.1523
830	0.310		0.1119	0	0.822		0.750	0
850	-0.071		0.1440	0	0.83		0.750	0
870	-0.082		0.1547	0	0.83		0.750	0
890	-0.083		0.1498	0	0.83		0.750	0
910	-0.083		0.1469	0	0.83		0.750	0
930	-0.084		0.1433	0	0.83		0.750	0
950	-0.084		0.1375	0	0.83		0.750	0
970	-0.085		0.1321	0	0.83		0.750	0

990	
550	

-0.085

0.1306

0

0.83

0

X (ft)	MASD_oil	MASD_gas	C_N2	C_CO2	C_C1	C_C10
10	42.769		4.5E-06	1.0E+00	1.0E-10	7.4E-06
30	42.769		8.9E-06	1.0E+00	1.0E-10	1.5E-05
50	42.781		2.2E-05	1.0E+00	1.0E-10	3.7E-05
70	42.914		5.7E-05	1.0E+00	1.0E-10	1.0E-04
90	43.791		1.5E-04	1.0E+00	1.0E-10	3.4E-04
110	45.071		4.2E-04	1.0E+00	1.2E-10	1.5E-03
130	45.055	41.790	1.3E-03	9.9E-01	3.4E-10	6.8E-03
150	44.877	24.685	4.7E-03	9.6E-01	1.9E-09	3.8E-02
170	43.663	14.037	1.4E-02	8.9E-01	5.7E-09	9.4E-02
190	42.511	9.939	4.4E-02	8.5E-01	1.8E-08	1.1E-01
210	42.021	8.552	8.2E-02	8.0E-01	3.0E-08	1.2E-01
230	41.973	8.415	1.5E-01	6.1E-01	5.9E-08	2.3E-01
250	41.972	8.407	2.6E-01	3.2E-01	1.5E-07	4.1E-01
270	41.972	8.399	3.6E-01	9.4E-02	3.9E-07	5.5E-01
290	41.970	8.389	4.0E-01	3.4E-03	9.5E-07	5.9E-01
310	41.965	8.377	4.1E-01	1.1E-10	2.2E-06	5.9E-01
330	41.951	8.355	4.1E-01	3.1E-11	4.9E-06	5.9E-01
350	41.911	8.305	4.1E-01	1.7E-13	1.0E-05	5.9E-01
370	41.818	8.201	4.1E-01	1.7E-13	2.3E-05	5.9E-01
390	41.674	8.048	4.2E-01	7.1E-11	5.5E-05	5.8E-01
410	41.490	7.861	4.1E-01	6.7E-11	1.4E-04	5.9E-01
430	41.279	7.655	4.1E-01	6.9E-11	3.5E-04	5.9E-01
450	41.055	7.447	4.1E-01	2.8E-12	9.0E-04	5.9E-01
470	40.827	7.244	4.0E-01	3.1E-13	2.5E-03	5.9E-01
490	40.601	7.053	4.0E-01	6.4E-13	7.1E-03	5.9E-01
510	40.384	6.877	3.9E-01	4.3E-12	1.9E-02	5.9E-01
530	40.185	6.722	3.7E-01	2.3E-13	4.0E-02	5.9E-01
550	40.010	6.591	3.5E-01	2.3E-13	6.8E-02	5.8E-01
570	39.869	6.487	3.3E-01	2.2E-13	1.0E-01	5.7E-01
590	39.759	6.407	3.1E-01	1.9E-13	1.3E-01	5.6E-01
610	40.074		2.8E-01	2.1E-13	1.7E-01	5.5E-01
630	40.988		2.6E-01	1.8E-13	2.0E-01	5.4E-01
650	40.988		2.4E-01	2.2E-13	2.4E-01	5.3E-01
670	40.988		2.2E-01	1.6E-13	2.7E-01	5.2E-01
690	40.987		2.0E-01	2.2E-13	3.0E-01	5.1E-01
710	40.987		2.0E-01	1.9E-13	3.4E-01	4.6E-01
730	40.987		2.0E-01	1.6E-13	4.0E-01	4.0E-01
750	40.987		1.8E-01	1.8E-13	4.3E-01	4.0E-01
770	40.986		1.6E-01	1.9E-13	4.4E-01	4.0E-01

790	40.986	1.4E-01	1.7E-13	4.4E-01	4.2E-01
810	40.986	9.0E-02	2.3E-11	3.7E-01	5.4E-01
830	40.986	1.8E-02	2.8E-11	2.3E-01	7.5E-01
850	40.985	5.0E-04	1.6E-13	2.0E-01	8.0E-01
870	40.985	1.0E-10	1.6E-13	2.0E-01	8.0E-01
890	40.985	1.5E-11	1.6E-13	2.0E-01	8.0E-01
910	40.985	1.6E-13	1.6E-13	2.0E-01	8.0E-01
930	40.984	1.6E-13	1.6E-13	2.0E-01	8.0E-01
950	40.984	1.6E-13	1.6E-13	2.0E-01	8.0E-01
970	40.984	1.6E-13	1.6E-13	2.0E-01	8.0E-01
990	40.984	1.6E-13	1.6E-13	2.0E-01	8.0E-01

## EXAMPLE 8-3 DATA

Results after 125 days:

X (ft)	GFE2	TNUM2	S2	ENDKRL2	RPERM2	GFE3	S3	ENDKRL3	RPERM3
10	-	6E-08	0	0.3	0	7.251	0.751	0.685	0.686
30	-	6E-08	0	0.3	0	7.251	0.751	0.685	0.686
50	-	6E-08	0	0.3	0	7.25	0.751	0.685	0.686
70	-	6E-08	0	0.3	0	7.25	0.751	0.685	0.686
90	-	6E-08	0	0.3	0	7.25	0.751	0.685	0.686
110	-	6E-08	0	0.3	0	7.25	0.751	0.685	0.686
130	-	6E-08	0	0.3	0	7.25	0.751	0.685	0.686
150	-	6E-08	0	0.3	0	7.249	0.751	0.685	0.685
170	-	6E-08	0	0.3	0	7.249	0.751	0.685	0.685
190	-	6E-08	0	0.3	0	7.249	0.751	0.685	0.685
210	-	6E-08	0	0.3	0	7.249	0.751	0.685	0.685
230	-	6E-08	0	0.3	0	7.249	0.751	0.685	0.685
250	-	6E-08	0	0.3	0	7.249	0.751	0.685	0.685
270	-	6E-08	0	0.3	0	7.248	0.751	0.685	0.685
290	-	6E-08	0	0.3	0	7.248	0.751	0.684	0.685
310	-	6E-08	0	0.3	0	7.248	0.751	0.684	0.685
330	-	6E-08	0	0.3	0	7.247	0.751	0.684	0.685
350	-	6E-08	0	0.3	0	7.245	0.751	0.684	0.685
370	-	6E-08	0	0.3	0	7.238	0.751	0.682	0.683
390	-	6E-08	0	0.3	0	7.209	0.751	0.676	0.677
410	-	7E-08	0	0.3	0	7.102	0.751	0.653	0.654
430	-	8E-08	0	0.3	0	6.76	0.751	0.579	0.58
450	-	1.3E-07	0	0.3	0	6.329	0.751	0.486	0.487

470	6.114	0.0039	0.354	0.439	0.039	6.213	0.397	0.461	0.121
490	5.966	0.000101	0.386	0.407	0.061	6.232	0.365	0.465	0.078
510	5.72	1.03E-05	0.411	0.354	0.072	6.179	0.34	0.453	0.048
530	5.451	2.74E-06	0.427	0.3	0.073	6.114	0.324	0.439	0.033
550	5.311	1.26E-06	0.437	0.3	0.084	6.19	0.314	0.456	0.028
570	5.322	7.6E-07	0.461	0.3	0.104	6.439	0.289	0.509	0.025
590	5.421	5.8E-07	0.49	0.3	0.127	6.732	0.261	0.573	0.023
610	5.467	5.4E-07	0.5	0.3	0.135	6.838	0.25	0.596	0.022
630	5.465	5.3E-07	0.501	0.3	0.136	6.838	0.249	0.596	0.022
650	5.463	5.3E-07	0.501	0.3	0.137	6.838	0.249	0.596	0.021
670	5.46	5.3E-07	0.501	0.3	0.137	6.839	0.249	0.596	0.021
690	5.458	5.3E-07	0.501	0.3	0.137	6.839	0.249	0.596	0.022
710	5.456	5.2E-07	0.501	0.3	0.136	6.839	0.249	0.596	0.022
730	5.453	5.2E-07	0.501	0.3	0.136	6.84	0.249	0.596	0.022
750	5.451	5.2E-07	0.501	0.3	0.136	6.84	0.249	0.596	0.022
770	5.449	5.2E-07	0.501	0.3	0.136	6.84	0.249	0.596	0.022
790	5.446	5.1E-07	0.5	0.3	0.136	6.841	0.249	0.596	0.022
810	5.444	5.1E-07	0.5	0.3	0.134	6.841	0.25	0.596	0.022
830	5.441	5.1E-07	0.499	0.3	0.132	6.841	0.251	0.596	0.023
850	5.439	5E-07	0.497	0.3	0.129	6.842	0.253	0.597	0.025
870	5.437	5E-07	0.496	0.3	0.126	6.842	0.254	0.597	0.026
890	5.434	4.9E-07	0.495	0.3	0.125	6.842	0.254	0.597	0.026
910	5.432	4.9E-07	0.495	0.3	0.125	6.842	0.254	0.597	0.026
930	5.43	4.9E-07	0.496	0.3	0.126	6.843	0.254	0.597	0.026
950	5.427	4.9E-07	0.497	0.3	0.128	6.843	0.253	0.597	0.025
970	5.425	4.9E-07	0.498	0.3	0.131	6.843	0.251	0.597	0.024
990	5.4	4.9E-07	0.498	0.3	0.131	6.801	0.251	0.588	0.024

## EXAMPLE 8-4 DATA

Results after 300 days in layer 5:

X (ft)	GFE2	TNUM2	IFT2	PR2	E2	S2	RPERM2
20	-2.733	3.5E-07	6.654	0.315	2.956	0.025	0
60	-2.74	4E-07	6.676	0.332	2.908	0.066	0
100	-2.749	4.5E-07	6.702	0.323	2.935	0.044	0
140	-2.758	4E-07	6.727	0.318	2.949	0.033	0
180	-2.766	4E-07	6.751	0.315	2.958	0.026	0
220	-2.774	4.5E-07	6.775	0.313	2.961	0.023	0
260	-2.781	4.5E-07	6.795	0.313	2.962	0.022	0
300	-2.781	5E-07	6.802	0.314	2.961	0.022	0
340	-2.778	5E-07	6.802	0.315	2.958	0.024	0

380	-2.755	5.5E-07	6.759	0.316	2.955	0.026	0
420	-2.75	5.5E-07	6.76	0.317	2.952	0.028	0
460	-2.704	5.5E-07	6.675	0.318	2.948	0.03	0
500	-2.344	6E-07	5.989	0.338	2.919	0.035	0
540	-0.022	1.55E-06	2.496	0.467	2.736	0.054	0
580	3.034	4.79E-05	0.123	0.725	2.119	0.154	0.003
620	3.687	4.5E-07	20	0.634	2.582	0.626	0.358
660	1.685	6.5E-07	20	0.53	2.713	0.701	0.418
700	1.75	2.9E-06	5.536	0.743	1.941	0.643	0.609
740	1.759	3.6E-06	5.61	0.625	2.374	0.604	0.452
780	1.575	4.35E-06	6.261	0.569	2.557	0.564	0.332
820	1.55	5.4E-06	6.58	0.574	2.538	0.568	0.342
860	1.498	5.8E-06	7.116	0.574	2.53	0.62	0.462
900	1.024	5.2E-06	8.809	0.551	2.562	0.622	0.446
940	0.171	4.7E-06	11.648	0.509	2.618	0.622	0.407
980	-0.589	4.15E-06	14.493	0.471	2.671	0.619	0.367
X (ft)	GFE3	IFT3	SR3	PR3	E3	S3	RPERM3
20	-	0	0	0.441	2.823	0	0
60	-	0	0	0.441	2.823	0	0
100	-	0	0	0.441	2.823	0	0
140	-	0	0	0.441	2.823	0	0
180	-	0	0	0.441	2.823	0	0
220	-	0	0	0.441	2.823	0	0
260	-	0	0	0.441	2.823	0	0
300	-	0	0	0.441	2.823	0	0
340	-	0	0	0.441	2.823	0	0
380	-	0	0	0.441	2.823	0	0
420	-	0	0	0.95	1.102	0	0
400 500	-	0	0	0.945	1.170	0	0
540	-	0	0	0.950	1.200	0	0
580	-	0	0	0.678	1.4 2.108	0	0
530 620		0	0	0.033	2.190	0	0
660	_	0	0	0.443	2.019	0	0
700	6 061	5 536	0 055	0.445	2.017	0 057	0
740	6.001	5.61	0.055	0.839	2.110	0.057	0
780	5 985	6 261	0.00	0.000	2.119	0.005	0 001
820	5.905	6 58	0.089	0.832	2.103	0.105	0.001
860	5 835	7,116	0.089	0.822	2.151	0.114	0.001
900	5 81	8,809	0.089	0.819	2,162	0.117	0.002
940	5 871	11,648	0.089	0.825	2.148	0.116	0.002
980	5.991	14.493	0.09	0.839	2.117	0.114	0.002

X (ft)	GFE4	IFT4	SR4	PR4	E4	S4	RPERM
20	6.656	6.654	0.098	0.992	1.082	0.734	0.697
60	6.655	6.676	0.095	0.979	1.214	0.647	0.578
100	6.654	6.702	0.097	0.986	1.141	0.64	0.578
140	6.653	6.727	0.097	0.99	1.105	0.646	0.589
180	6.652	6.751	0.098	0.992	1.083	0.644	0.591
220	6.651	6.775	0.098	0.993	1.073	0.644	0.592
260	6.649	6.795	0.098	0.993	1.069	0.65	0.599
300	6.647	6.802	0.098	0.993	1.07	0.66	0.611
340	6.644	6.802	0.098	0.992	1.075	0.67	0.622
380	6.638	6.759	0.098	0.992	1.082	0.676	0.628
420	6.635	6.76	0.098	0.991	1.089	0.677	0.629
460	6.627	6.675	0.097	0.99	1.098	0.676	0.627
500	6.584	5.989	0.097	0.989	1.114	0.672	0.619
540	6.282	2.496	0.095	0.971	1.237	0.648	0.56
580	5.347	0.123	0.069	0.836	1.902	0.517	0.252
620	-	0	0	0.441	2.823	0	0
660	-	0	0	0.441	2.823	0	0
700	-	0	0	0.441	2.823	0	0
740	-	0	0	0.441	2.823	0	0
780	-	0	0	0.441	2.823	0	0
820	-	0	0	0.441	2.823	0	0
860	-	0	0	0.441	2.823	0	0
900	-	0	0	0.441	2.823	0	0
940	-	0	0	0.441	2.823	0	0
980	-	0	0	0.441	2.823	0	0

Mole % in phase 2:

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X (ft)	CO2	C1	C2-3	C4-6	C7-15	C16+
20	0.587853	0.000007	0.000014	0.000026	0.000108	0.411991
60	0.587635	0.000007	0.000014	0.000026	0.000113	0.412205
100	0.587373	0.000007	0.000014	0.000026	0.000126	0.412453
140	0.587115	0.000007	0.000014	0.000027	0.000161	0.412676
180	0.58687	0.000007	0.000014	0.000027	0.000241	0.41284
220	0.586628	0.000008	0.000015	0.000029	0.000364	0.412956
260	0.586404	0.000008	0.000016	0.000033	0.00065	0.412888
300	0.586276	0.00001	0.000021	0.000045	0.001475	0.412174
340	0.586192	0.000015	0.000029	0.000068	0.002553	0.411142
380	0.586432	0.00002	0.000039	0.000092	0.005048	0.408369
420	0.586335	0.000027	0.000051	0.000125	0.006191	0.407272

460	0.586852	0.000054	0.000102	0.000245	0.010071	0.402676
500	0.591763	0.000346	0.000592	0.001298	0.032471	0.37353
540	0.626168	0.005272	0.007276	0.012536	0.132354	0.216393
580	0.650847	0.053148	0.047526	0.049769	0.137352	0.061358
620	0.535904	0.150601	0.099421	0.076747	0.105701	0.031626
660	0.155798	0.281229	0.17908	0.136577	0.177307	0.070009
700	0.176348	0.275771	0.173424	0.13155	0.174033	0.068875
740	0.208702	0.256142	0.165998	0.127368	0.173592	0.068197
780	0.207659	0.246497	0.164504	0.12864	0.180961	0.07174
820	0.245946	0.219204	0.155763	0.125668	0.182119	0.0713
860	0.274266	0.191801	0.152577	0.126531	0.184377	0.070449
900	0.228357	0.189467	0.160903	0.138905	0.204775	0.077592
940	0.114659	0.205874	0.187228	0.160505	0.236408	0.095326
980	0.027623	0.205819	0.208408	0.179691	0.265466	0.112992

Mole % in phase 3:

X (ft)	CO2	C1	C2-3	C4-6	C7-15	C16+
20	0	0	0	0	0	0
60	0	0	0	0	0	0
100	0	0	0	0	0	0
140	0	0	0	0	0	0
180	0	0	0	0	0	0
220	0	0	0	0	0	0
260	0	0	0	0	0	0
300	0	0	0	0	0	0
340	0	0	0	0	0	0
380	0	0	0	0	0	0
420	0	0	0	0	0	0
460	0	0	0	0	0	0
500	0	0	0	0	0	0
540	0	0	0	0	0	0
580	0	0	0	0	0	0
620	0	0	0	0	0	0
660	0	0	0	0	0	0
700	0.222199	0.649299	0.108256	0.019085	0.00116	0
740	0.265589	0.610947	0.104012	0.018332	0.00112	0
780	0.268982	0.610975	0.101884	0.017205	0.000954	0
820	0.325067	0.56132	0.096598	0.016165	0.000849	0
860	0.373137	0.516562	0.094442	0.015164	0.000695	0
900	0.326838	0.560723	0.097792	0.014161	0.000487	0
940	0.177733	0.695933	0.112537	0.013481	0.000317	0
980	0.04765	0.81066	0.128365	0.013106	0.000219	0

Mole % in phase 4:

X (ft)	CO2	C1	C2-3	C4-6	C7-15	C16+
20	0.998947	0.00001	0.00001	0.00001	0.000011	0.001012
60	0.998954	0.00001	0.00001	0.00001	0.000011	0.001005
100	0.998961	0.00001	0.00001	0.00001	0.000012	0.000997
140	0.998966	0.00001	0.00001	0.00001	0.000016	0.000988
180	0.998965	0.00001	0.00001	0.000011	0.000024	0.00098
220	0.998961	0.000011	0.000011	0.000011	0.000036	0.000971
260	0.998938	0.000012	0.000012	0.000013	0.000063	0.000963
300	0.998855	0.000015	0.000015	0.000017	0.000144	0.000954
340	0.998736	0.000021	0.000021	0.000026	0.000248	0.000947
380	0.998474	0.000028	0.000028	0.000036	0.000492	0.000942
420	0.99834	0.000038	0.000037	0.000048	0.000603	0.000933
460	0.997838	0.000077	0.000074	0.000095	0.000984	0.000932
500	0.994262	0.000492	0.000433	0.000511	0.003319	0.000983
540	0.960872	0.006971	0.005571	0.005689	0.019354	0.001543
580	0.799689	0.063255	0.042873	0.034604	0.054331	0.005248
620	0	0	0	0	0	0
660	0	0	0	0	0	0
700	0	0	0	0	0	0
740	0	0	0	0	0	0
780	0	0	0	0	0	0
820	0	0	0	0	0	0
860	0	0	0	0	0	0
900	0	0	0	0	0	0
940	0	0	0	0	0	0
980	0	0	0	0	0	0

# EXAMPLE 8-5 DATA

1D

X (ft)	GFE2	SRL2	ENDKRL2	EXPL2	Т2	TNUM2	IFT2	SR2	PR2	E2	S2	RPERM2
10	-8.62	0.244	0.322	2.969	15310	1.84E-06	0.009	0.202	0.422	2.678	0.233	0
30	-8.618	0.244	0.322	2.969	15310	1.95E-06	0.009	0.182	0.413	2.703	0.213	0
50	-8.614	0.244	0.322	2.969	15312	2.06E-06	0.009	0.163	0.407	2.721	0.194	0
70	-8.604	0.244	0.322	2.969	15315	1.85E-06	0.009	0.145	0.401	2.741	0.174	0
90	-8.58	0.244	0.323	2.968	15323	1.51E-06	0.009	0.128	0.394	2.761	0.154	0
110	-8.504	0.243	0.324	2.965	15348	1.32E-06	0.008	0.114	0.39	2.773	0.138	0
130	-8.174	0.241	0.332	2.954	15458	1.31E-06	0.008	0.107	0.396	2.768	0.129	0

150	-6.713	0.231	0.366	2.906	15944	1.8E-06	0.006	0.112	0.434	2.701	0.135	0
170	-4.779	0.218	0.411	2.841	16588	3.4E-06	0.004	0.131	0.495	2.578	0.157	0
190	-4.121	0.214	0.427	2.819	16807	4.7E-06	0.003	0.139	0.522	2.516	0.166	0
210	-4.117	0.214	0.427	2.819	16809	4.63E-06	0.003	0.134	0.521	2.521	0.16	0
230	-4.125	0.214	0.426	2.819	16806	4.34E-06	0.003	0.128	0.516	2.534	0.153	0
250	-4.114	0.214	0.427	2.819	16810	4.14E-06	0.003	0.122	0.514	2.544	0.147	0
270	-4.036	0.213	0.428	2.816	16835	4.08E-06	0.003	0.117	0.513	2.547	0.141	0
290	-3.763	0.211	0.435	2.807	16926	4.38E-06	0.003	0.115	0.521	2.533	0.138	0
310	-3.341	0.209	0.445	2.793	17067	5.07E-06	0.002	0.115	0.535	2.502	0.138	0
330	-2.915	0.206	0.455	2.779	17209	6.06E-06	0.002	0.115	0.551	2.464	0.138	0
350	-2.564	0.203	0.463	2.767	17325	7.2E-06	0.002	0.115	0.567	2.425	0.138	0
370	-2.309	0.202	0.469	2.759	17410	8.29E-06	0.002	0.113	0.579	2.393	0.136	0
390	-2.109	0.2	0.473	2.752	17477	9.49E-06	0.002	0.112	0.591	2.362	0.134	0
410	-1.893	0.199	0.478	2.745	17549	1.18E-05	0.001	0.111	0.61	2.306	0.133	0
430	-1.61	0.197	0.485	2.736	17643	1.69E-05	0.001	0.111	0.643	2.202	0.134	0
450	-1.227	0.195	0.494	2.723	17771	2.75E-05	0.001	0.109	0.698	2.03	0.139	0.001
470	-0.762	0.191	0.505	2.707	17926	5.62E-05	0	0.08	0.784	1.745	0.148	0.01
490	-0.254	0.188	0.517	2.691	18095	0.000262	0	0.028	0.8	1.253	0.165	0.071
510	0.453	0.183	0.533	2.667	18330	0.011391	0	0.001	0.8	1.2	0.224	0.177
530	1.041	0.179	0.547	2.647	18526	6.688096	0	0	0.8	1.2	0.421	0.337
550	0.935	0.18	0.544	2.651	18490	0.025844	0	0	0.8	1.2	0.59	0.471
570	0.291	0.184	0.529	2.672	18276	2.3E-07	1.097	0.178	0.529	2.672	0.597	0.388
590	-2.608	0.204	0.462	2.769	17311	4.3E-07	2.805	0.197	0.462	2.769	0.619	0.348
610	-5.168	0.221	0.402	2.854	16459	7.4E-07	4.548	0.214	0.402	2.854	0.645	0.304
630	-6.229	0.228	0.377	2.889	16106	1.01E-06	5.402	0.223	0.378	2.889	0.684	0.288
650	-6.914	0.232	0.361	2.912	15877	1.01E-06	20	0.231	0.362	2.912	0.703	0.274
670	-7.443	0.236	0.349	2.93	15701	1.01E-06	20	0.235	0.349	2.929	0.699	0.258
690	-7.56	0.237	0.346	2.934	15662	1.01E-06	20	0.235	0.347	2.933	0.696	0.249
710	-7.605	0.237	0.345	2.935	15647	1.01E-06	20	0.236	0.346	2.935	0.693	0.245
730	-7.475	0.236	0.348	2.931	15691	1.01E-06	20	0.235	0.349	2.93	0.69	0.242
750	-7.209	0.234	0.355	2.922	15779	1.16E-06	6.341	0.229	0.355	2.921	0.675	0.244
770	-7.384	0.236	0.35	2.928	15721	1.11E-06	6.491	0.23	0.351	2.927	0.669	0.24
790	-7.568	0.237	0.346	2.934	15660	1.11E-06	6.647	0.231	0.346	2.933	0.667	0.236
810	-7.761	0.238	0.342	2.94	15596	1.11E-06	6.808	0.232	0.342	2.94	0.665	0.231
830	-7.962	0.239	0.337	2.947	15529	1.11E-06	6.976	0.233	0.337	2.946	0.663	0.227
850	-8.172	0.241	0.332	2.954	15459	1.11E-06	7.149	0.235	0.332	2.953	0.66	0.223
870	-8.393	0.242	0.327	2.961	15385	1.1E-06	7.329	0.236	0.327	2.961	0.658	0.219
890	-8.624	0.244	0.322	2.969	15308	1.1E-06	7.516	0.237	0.322	2.968	0.656	0.214
910	-8.868	0.245	0.316	2.977	15227	1.11E-06	7.71	0.239	0.316	2.976	0.653	0.209
930	-9.125	0.247	0.31	2.986	15141	1.11E-06	7.911	0.24	0.31	2.985	0.651	0.204
950	-9.397	0.249	0.304	2.995	15051	1.11E-06	8.121	0.242	0.304	2.994	0.648	0.199
970	-9.683	0.25	0.3	3	15000	1.1E-06	8.339	0.243	0.3	2.999	0.646	0.196
990	-9.983	0.25	0.3	3	15000	1.08E-06	8.562	0.242	0.3	2.999	0.641	0.195

X (ft)	SRL3	ENDKRL3	EXPL3	Т3	TNUM3	IFT3	SR3	PR3	E3	S3	RPERM	GFE3
10		0.186	0.523	2.682	18179	0	0	0	0.523	2.682	0	0
30		0.186	0.523	2.682	18179	0	0	0	0.523	2.682	0	0
50		0.186	0.523	2.682	18179	1E-08	0	0	0.681	2.125	0	0
70		0.186	0.523	2.682	18179	2E-08	0	0	0.578	2.487	0	0
90		0.186	0.523	2.682	18179	1E-08	0	0	0.573	2.505	0	0
110		0.186	0.523	2.682	18179	1E-08	0	0	0.569	2.518	0	0
130		0.186	0.523	2.682	18179	1E-08	0	0	0.568	2.522	0	0
150		0.186	0.523	2.682	18179	1E-08	0	0	0.574	2.502	0	0
170		0.186	0.523	2.682	18179	1E-08	0	0	0.591	2.442	0	0
190		0.186	0.523	2.682	18179	1E-08	0	0	0.602	2.402	0	0
210		0.186	0.523	2.682	18179	1E-08	0	0	0.601	2.406	0	0
230		0.186	0.523	2.682	18179	1E-08	0	0	0.597	2.418	0	0
250		0.186	0.523	2.682	18179	1E-08	0	0	0.595	2.427	0	0
270		0.186	0.523	2.682	18179	1E-08	0	0	0.593	2.432	0	0
290		0.186	0.523	2.682	18179	1E-08	0	0	0.595	2.426	0	0
310		0.186	0.523	2.682	18179	1E-08	0	0	0.6	2.409	0	0
330		0.186	0.523	2.682	18179	1E-08	0	0	0.607	2.384	0	0
350		0.186	0.523	2.682	18179	1E-08	0	0	0.615	2.356	0	0
370		0.186	0.523	2.682	18179	1E-08	0	0	0.622	2.332	0	0
390		0.186	0.523	2.682	18179	1E-08	0	0	0.629	2.307	0	0
410		0.186	0.523	2.682	18179	1E-08	0	0	0.643	2.259	0	0
430		0.186	0.523	2.682	18179	2E-08	0	0	0.669	2.165	0	0
450		0.186	0.523	2.682	18179	2E-08	0	0	0.715	2.005	0	0
470		0.186	0.523	2.682	18179	2E-08	0	0	0.792	1.734	0	0
490		0.186	0.523	2.682	18179	2E-08	0	0	0.8	1.252	0	0
510		0.186	0.523	2.682	18179	4E-08	0	0	0.8	1.007	0	0
530		0.186	0.523	2.682	18179	7E-08	0	0	0.8	1	0	0
550		0.186	0.523	2.682	18179	9E-08	0	0	0.8	1.003	0	0
570	6.068	0.109	0.731	2.297	24067	2.3E-07	1.097	0.101	0.741	2.249	0.114	0
590	6.332	0.091	0.767	2.207	25865	4.3E-07	2.805	0.085	0.775	2.166	0.091	0
610	6.73	0.064	0.821	2.072	28569	7.4E-07	4.548	0.06	0.8	2.039	0.063	0
630	7.041	0.05	0.85	2	30000	1.01E-06	5.402	0.02	0.8	1.978	0.021	0
650		0.186	0.523	2.682	18179	6.54E-06	0	0	0.525	2.673	0	0
670		0.186	0.523	2.682	18179	7.2E-06	0	0	0.525	2.673	0	0
690		0.186	0.523	2.682	18179	7.57E-06	0	0	0.525	2.672	0	0
710		0.186	0.523	2.682	18179	7.64E-06	0	0	0.525	2.672	0	0
730		0.186	0.523	2.682	18179	7.59E-06	0	0	0.525	2.672	0	0

750	6.97	0.05	0.85	2	30000	1.16E-06	6.341	0.014	0.8	1.978	0.014	0
770	6.944	0.05	0.85	2	30000	1.11E-06	6.491	0.021	0.8	1.976	0.021	0
790	6.916	0.052	0.847	2.008	29839	1.11E-06	6.647	0.022	0.8	1.984	0.022	0
810	6.887	0.054	0.843	2.018	29638	1.11E-06	6.808	0.024	0.8	1.993	0.024	0
830	6.855	0.056	0.838	2.029	29423	1.11E-06	6.976	0.026	0.8	2.003	0.026	0
850	6.821	0.058	0.834	2.04	29191	1.11E-06	7.149	0.028	0.8	2.014	0.029	0
870	6.784	0.061	0.829	2.053	28941	1.1E-06	7.329	0.03	0.8	2.025	0.031	0
890	6.744	0.063	0.823	2.067	28670	1.1E-06	7.516	0.033	0.8	2.038	0.033	0
910	6.701	0.066	0.817	2.081	28375	1.11E-06	7.71	0.035	0.8	2.052	0.036	0
930	6.654	0.069	0.811	2.097	28051	1.11E-06	7.911	0.037	0.8	2.066	0.038	0
950	6.601	0.073	0.804	2.115	27695	1.11E-06	8.121	0.04	0.8	2.083	0.041	0
970	6.543	0.077	0.796	2.135	27301	1.1E-06	8.339	0.043	0.8	2.101	0.044	0
990	6.479	0.081	0.787	2.157	26866	1.08E-06	8.562	0.047	0.794	2.121	0.048	0

X (ft)	GFE4	SRL4	ENDKRL4	EXPL4	Τ4	TNUM4	IFT4	SR4	PR4	E4	S4	RPERM
10	5.396	0.15	0.648	2.502	19975	1.84E-06	0.009	0.128	0.709	2.243	0.5	0.189
30	5.395	0.15	0.648	2.502	19975	1.95E-06	0.009	0.13	0.738	2.121	0.475	0.171
50	5.395	0.15	0.648	2.502	19975	2.06E-06	0.009	0.132	0.765	2.005	0.463	0.169
70	5.395	0.151	0.648	2.503	19975	1.85E-06	0.009	0.133	0.79	1.895	0.476	0.193
90	5.394	0.151	0.648	2.503	19975	1.51E-06	0.009	0.135	0.8	1.787	0.507	0.236
110	5.391	0.151	0.648	2.503	19974	1.32E-06	0.008	0.136	0.8	1.706	0.535	0.273
130	5.381	0.151	0.648	2.503	19970	1.31E-06	0.008	0.136	0.8	1.665	0.554	0.298
150	5.336	0.151	0.647	2.504	19956	1.8E-06	0.006	0.135	0.8	1.728	0.556	0.293
170	5.275	0.151	0.645	2.506	19935	3.4E-06	0.004	0.13	0.787	1.907	0.539	0.255
190	5.254	0.151	0.645	2.507	19928	4.7E-06	0.003	0.126	0.769	1.981	0.534	0.24
210	5.253	0.151	0.645	2.507	19928	4.63E-06	0.003	0.127	0.777	1.947	0.541	0.252
230	5.253	0.151	0.645	2.507	19928	4.34E-06	0.003	0.128	0.787	1.905	0.548	0.266
250	5.249	0.151	0.645	2.507	19927	4.14E-06	0.003	0.129	0.797	1.863	0.556	0.28
270	5.237	0.152	0.645	2.508	19923	4.08E-06	0.003	0.129	0.8	1.83	0.563	0.291
290	5.203	0.152	0.644	2.509	19911	4.38E-06	0.003	0.129	0.8	1.82	0.566	0.295
310	5.147	0.152	0.642	2.511	19892	5.07E-06	0.002	0.127	0.8	1.83	0.567	0.295
330	5.085	0.153	0.641	2.513	19872	6.06E-06	0.002	0.126	0.799	1.845	0.567	0.294
350	5.028	0.153	0.64	2.515	19853	7.2E-06	0.002	0.123	0.797	1.854	0.568	0.294
370	4.98	0.153	0.639	2.516	19837	8.29E-06	0.002	0.121	0.797	1.852	0.57	0.297
390	4.929	0.154	0.637	2.518	19820	9.49E-06	0.002	0.119	0.798	1.846	0.573	0.301
410	4.842	0.154	0.635	2.521	19791	1.18E-05	0.001	0.115	0.797	1.845	0.575	0.304
430	4.714	0.155	0.632	2.525	19748	1.69E-05	0.001	0.107	0.792	1.862	0.574	0.304
450	4.551	0.156	0.629	2.531	19694	2.75E-05	0.001	0.093	0.792	1.858	0.57	0.304
470	4.273	0.158	0.622	2.54	19602	5.62E-05	0	0.069	0.8	1.642	0.561	0.325
490	3.715	0.162	0.609	2.558	19416	0.000262	0	0.024	0.8	1.229	0.544	0.383
510	2.975	0.167	0.592	2.583	19170	0.011391	0	0.001	0.8	1.006	0.485	0.386
530	2.737	0.168	0.586	2.591	19090	6.688096	0	0	0.8	1	0.287	0.23
550	3.33	0.164	0.6	2.571	19288	0.025844	0	0	0.8	1.003	0.116	0.092

570	0.186	0.523	2.682	18179	4E-08	30	0	0.523	2.682	0	0
590	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
610	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
630	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
650	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
670	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
690	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
710	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
730	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
750	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
770	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
790	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
810	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
830	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
850	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
870	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
890	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
910	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
930	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
950	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
970	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0
990	0.186	0.523	2.682	18179	0	30	0	0.523	2.682	0	0

Mole % in phase 2:

X (ft)	C_CO2	C_C1	C_C2	C_C3	C_C4	C_C5	C_C6	C_C79	C_C10	C_C14	C_C20	C_C36
10	0.4488	0.0000	0.0000	0.0027	0.0737	0.0487	0.0365	0.0399	0.0000	0.0000	0.0001	0.3497
30	0.4488	0.0000	0.0000	0.0027	0.0737	0.0487	0.0365	0.0399	0.0000	0.0000	0.0002	0.3496
50	0.4488	0.0000	0.0000	0.0027	0.0737	0.0487	0.0365	0.0399	0.0000	0.0000	0.0004	0.3493
70	0.4489	0.0000	0.0000	0.0027	0.0737	0.0487	0.0365	0.0399	0.0000	0.0000	0.0008	0.3487
90	0.4491	0.0000	0.0000	0.0027	0.0738	0.0487	0.0365	0.0399	0.0000	0.0000	0.0019	0.3474
110	0.4497	0.0000	0.0000	0.0027	0.0739	0.0488	0.0365	0.0399	0.0000	0.0000	0.0052	0.3433
130	0.4524	0.0000	0.0000	0.0027	0.0742	0.0491	0.0365	0.0398	0.0000	0.0000	0.0185	0.3267
150	0.4651	0.0000	0.0000	0.0028	0.0760	0.0504	0.0365	0.0397	0.0000	0.0000	0.0697	0.2597
170	0.4854	0.0000	0.0000	0.0030	0.0790	0.0527	0.0366	0.0396	0.0000	0.0000	0.1230	0.1807
190	0.4935	0.0000	0.0000	0.0031	0.0802	0.0536	0.0367	0.0395	0.0000	0.0001	0.1371	0.1562
210	0.4936	0.0000	0.0000	0.0031	0.0802	0.0536	0.0367	0.0395	0.0000	0.0002	0.1371	0.1561
230	0.4935	0.0000	0.0000	0.0031	0.0801	0.0536	0.0367	0.0395	0.0000	0.0006	0.1366	0.1564
250	0.4937	0.0000	0.0000	0.0031	0.0801	0.0536	0.0366	0.0395	0.0000	0.0019	0.1356	0.1559
270	0.4947	0.0000	0.0000	0.0031	0.0801	0.0536	0.0365	0.0393	0.0000	0.0062	0.1332	0.1533
290	0.4982	0.0000	0.0000	0.0031	0.0801	0.0535	0.0363	0.0389	0.0000	0.0181	0.1271	0.1446
310	0.5037	0.0000	0.0000	0.0032	0.0801	0.0535	0.0360	0.0383	0.0000	0.0352	0.1180	0.1319

330	0.5098	0.0000	0.0000	0.0032	0.0801	0.0534	0.0356	0.0376	0.0001	0.0517	0.1089	0.1197
350	0.5151	0.0000	0.0000	0.0032	0.0800	0.0533	0.0352	0.0370	0.0004	0.0643	0.1015	0.1100
370	0.5193	0.0000	0.0000	0.0033	0.0799	0.0532	0.0348	0.0364	0.0012	0.0723	0.0965	0.1030
390	0.5230	0.0000	0.0000	0.0033	0.0796	0.0530	0.0344	0.0358	0.0040	0.0765	0.0930	0.0976
410	0.5274	0.0001	0.0000	0.0032	0.0787	0.0523	0.0336	0.0350	0.0113	0.0772	0.0894	0.0918
430	0.5337	0.0003	0.0000	0.0032	0.0772	0.0509	0.0321	0.0344	0.0220	0.0762	0.0855	0.0844
450	0.5431	0.0011	0.0000	0.0033	0.0741	0.0484	0.0296	0.0355	0.0338	0.0749	0.0814	0.0748
470	0.5539	0.0042	0.0001	0.0034	0.0684	0.0447	0.0267	0.0416	0.0442	0.0730	0.0765	0.0635
490	0.5575	0.0158	0.0003	0.0038	0.0610	0.0408	0.0247	0.0531	0.0516	0.0697	0.0700	0.0518
510	0.5382	0.0565	0.0011	0.0053	0.0541	0.0380	0.0237	0.0646	0.0559	0.0646	0.0611	0.0369
530	0.4813	0.1337	0.0026	0.0090	0.0474	0.0355	0.0233	0.0704	0.0570	0.0597	0.0538	0.0263
550	0.4164	0.1937	0.0038	0.0124	0.0424	0.0336	0.0229	0.0737	0.0595	0.0597	0.0539	0.0279
570	0.3717	0.2098	0.0042	0.0137	0.0403	0.0333	0.0233	0.0788	0.0669	0.0625	0.0579	0.0376
590	0.2346	0.2489	0.0043	0.0126	0.0298	0.0262	0.0216	0.0811	0.0772	0.0893	0.0948	0.0797
610	0.0848	0.3026	0.0043	0.0109	0.0212	0.0195	0.0201	0.0845	0.0856	0.1184	0.1331	0.1151
630	0.0095	0.3276	0.0042	0.0101	0.0195	0.0182	0.0201	0.0883	0.0906	0.1322	0.1502	0.1294
650	0.0004	0.3029	0.0041	0.0101	0.0199	0.0186	0.0208	0.0936	0.0957	0.1397	0.1585	0.1358
670	0.0004	0.2766	0.0041	0.0103	0.0208	0.0196	0.0221	0.0980	0.0998	0.1446	0.1636	0.1399
690	0.0004	0.2721	0.0041	0.0105	0.0212	0.0200	0.0226	0.0987	0.1005	0.1452	0.1642	0.1404
710	0.0004	0.2723	0.0041	0.0105	0.0212	0.0200	0.0226	0.0987	0.1005	0.1451	0.1641	0.1404
730	0.0004	0.2810	0.0041	0.0104	0.0210	0.0198	0.0223	0.0975	0.0993	0.1433	0.1621	0.1387
750	0.0004	0.2963	0.0041	0.0103	0.0206	0.0194	0.0218	0.0954	0.0971	0.1402	0.1586	0.1356
770	0.0004	0.2899	0.0041	0.0104	0.0208	0.0196	0.0220	0.0963	0.0980	0.1415	0.1600	0.1369
790	0.0004	0.2833	0.0041	0.0104	0.0210	0.0197	0.0222	0.0972	0.0990	0.1429	0.1616	0.1382
810	0.0004	0.2763	0.0041	0.0105	0.0211	0.0199	0.0224	0.0982	0.0999	0.1443	0.1632	0.1396
830	0.0004	0.2690	0.0041	0.0105	0.0213	0.0201	0.0227	0.0992	0.1010	0.1458	0.1649	0.1410
850	0.0004	0.2613	0.0041	0.0106	0.0215	0.0203	0.0229	0.1002	0.1021	0.1474	0.1667	0.1426
870	0.0004	0.2532	0.0041	0.0106	0.0217	0.0205	0.0231	0.1014	0.1032	0.1490	0.1685	0.1442
890	0.0004	0.2447	0.0041	0.0107	0.0219	0.0207	0.0234	0.1025	0.1044	0.1507	0.1705	0.1458
910	0.0004	0.2357	0.0041	0.0107	0.0221	0.0210	0.0237	0.1038	0.1057	0.1526	0.1726	0.1476
930	0.0004	0.2262	0.0041	0.0108	0.0224	0.0212	0.0240	0.1051	0.1070	0.1545	0.1748	0.1495
950	0.0004	0.2161	0.0041	0.0109	0.0226	0.0215	0.0243	0.1065	0.1085	0.1566	0.1771	0.1515
970	0.0004	0.2054	0.0040	0.0109	0.0229	0.0218	0.0246	0.1080	0.1100	0.1588	0.1796	0.1536
990	0.0004	0.1942	0.0040	0.0110	0.0232	0.0221	0.0250	0.1095	0.1116	0.1611	0.1822	0.1558

Mole % in Phase 3:

X (ft)	C_CO2	C_C1	C_C2	C_C3	C_C4	C_C5	C_C6	C_C79	C_C10	C_C14	C_C20	C_C36
10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
70	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
130	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
150	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
170	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
190	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
210	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
230	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
270	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
290	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
330	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
350	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
370	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
390	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
410	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
430	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
450	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
470	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
490	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
510	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
530	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
550	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
570	0.4932	0.4619	0.0045	0.0092	0.0140	0.0074	0.0032	0.0049	0.0014	0.0001	0.0000	0.0000
590	0.3149	0.6565	0.0046	0.0078	0.0078	0.0039	0.0017	0.0023	0.0005	0.0000	0.0000	0.0000
610	0.1106	0.8691	0.0046	0.0062	0.0045	0.0022	0.0011	0.0015	0.0003	0.0000	0.0000	0.0000
630	0.0123	0.9698	0.0044	0.0055	0.0038	0.0018	0.0009	0.0013	0.0002	0.0000	0.0000	0.0000
650	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
670	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
690	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
710	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
730	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750	0.0006	0.9825	0.0045	0.0053	0.0036	0.0016	0.0008	0.0009	0.0001	0.0000	0.0000	0.0000
770	0.0006	0.9826	0.0045	0.0053	0.0036	0.0016	0.0008	0.0009	0.0001	0.0000	0.0000	0.0000
790	0.0006	0.9827	0.0045	0.0054	0.0036	0.0015	0.0007	0.0008	0.0001	0.0000	0.0000	0.0000
810	0.0006	0.9827	0.0046	0.0054	0.0036	0.0015	0.0007	0.0008	0.0001	0.0000	0.0000	0.0000
830	0.0006	0.9828	0.0046	0.0054	0.0035	0.0015	0.0007	0.0008	0.0001	0.0000	0.0000	0.0000
850	0.0007	0.9828	0.0047	0.0054	0.0035	0.0015	0.0007	0.0007	0.0001	0.0000	0.0000	0.0000
870	0.0007	0.9827	0.0047	0.0055	0.0035	0.0015	0.0007	0.0007	0.0001	0.0000	0.0000	0.0000
890	0.0007	0.9827	0.0048	0.0055	0.0035	0.0014	0.0006	0.0007	0.0001	0.0000	0.0000	0.0000
910	0.0007	0.9826	0.0049	0.0056	0.0035	0.0014	0.0006	0.0006	0.0000	0.0000	0.0000	0.0000
930	0.0007	0.9824	0.0050	0.0057	0.0036	0.0014	0.0006	0.0006	0.0000	0.0000	0.0000	0.0000
950	0.0007	0.9822	0.0051	0.0058	0.0036	0.0014	0.0006	0.0006	0.0000	0.0000	0.0000	0.0000

970	0.0007	0.9819	0.0052	0.0059	0.0036	0.0014	0.0006	0.0005	0.0000	0.0000	0.0000	0.0000
990	0.0008	0.9816	0.0054	0.0060	0.0037	0.0014	0.0006	0.0005	0.0000	0.0000	0.0000	0.0000

Mole % in phase 4:

X (ft)	C_CO2	C_C1	C_C2	C_C3	C_C4	C_C5	C_C6	C_C79	C_C10	C_C14	C_C20	C_C36
10	0.8150	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0000	0.0000
30	0.8150	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0000	0.0000
50	0.8150	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0000	0.0000
70	0.8150	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0000	0.0000
90	0.8149	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0001	0.0000
110	0.8148	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0002	0.0000
130	0.8144	0.0000	0.0000	0.0043	0.0798	0.0522	0.0267	0.0220	0.0000	0.0000	0.0006	0.0000
150	0.8123	0.0000	0.0000	0.0043	0.0798	0.0522	0.0268	0.0222	0.0000	0.0000	0.0024	0.0000
170	0.8092	0.0000	0.0000	0.0043	0.0799	0.0523	0.0269	0.0224	0.0000	0.0000	0.0050	0.0000
190	0.8082	0.0000	0.0000	0.0043	0.0799	0.0523	0.0269	0.0224	0.0000	0.0000	0.0059	0.0000
210	0.8082	0.0000	0.0000	0.0043	0.0799	0.0523	0.0269	0.0224	0.0000	0.0000	0.0059	0.0000
230	0.8081	0.0000	0.0000	0.0043	0.0799	0.0523	0.0269	0.0224	0.0000	0.0001	0.0059	0.0000
250	0.8080	0.0000	0.0000	0.0043	0.0799	0.0523	0.0269	0.0224	0.0000	0.0002	0.0059	0.0000
270	0.8073	0.0000	0.0000	0.0043	0.0799	0.0523	0.0270	0.0224	0.0000	0.0008	0.0059	0.0000
290	0.8054	0.0000	0.0000	0.0043	0.0799	0.0523	0.0270	0.0225	0.0000	0.0024	0.0061	0.0000
310	0.8021	0.0000	0.0000	0.0043	0.0799	0.0523	0.0271	0.0227	0.0000	0.0051	0.0064	0.0000
330	0.7985	0.0000	0.0000	0.0043	0.0799	0.0524	0.0272	0.0228	0.0000	0.0082	0.0068	0.0000
350	0.7951	0.0000	0.0000	0.0042	0.0799	0.0523	0.0272	0.0229	0.0001	0.0110	0.0071	0.0000
370	0.7923	0.0000	0.0000	0.0042	0.0799	0.0523	0.0272	0.0229	0.0005	0.0132	0.0074	0.0000
390	0.7894	0.0000	0.0000	0.0042	0.0798	0.0522	0.0272	0.0229	0.0016	0.0148	0.0078	0.0000
410	0.7844	0.0001	0.0000	0.0042	0.0795	0.0520	0.0270	0.0230	0.0047	0.0164	0.0086	0.0001
430	0.7774	0.0003	0.0000	0.0041	0.0787	0.0513	0.0264	0.0235	0.0099	0.0184	0.0099	0.0001
450	0.7693	0.0014	0.0000	0.0041	0.0761	0.0492	0.0250	0.0254	0.0165	0.0210	0.0118	0.0002
470	0.7527	0.0052	0.0001	0.0042	0.0711	0.0463	0.0234	0.0317	0.0245	0.0252	0.0153	0.0004
490	0.7095	0.0188	0.0004	0.0046	0.0647	0.0433	0.0228	0.0447	0.0347	0.0329	0.0223	0.0013
510	0.6276	0.0638	0.0012	0.0061	0.0573	0.0403	0.0229	0.0592	0.0453	0.0414	0.0308	0.0041
530	0.5348	0.1476	0.0028	0.0101	0.0492	0.0368	0.0227	0.0659	0.0499	0.0425	0.0320	0.0057
550	0.4839	0.2294	0.0043	0.0143	0.0437	0.0343	0.0213	0.0644	0.0476	0.0326	0.0217	0.0025
570	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
590	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
610	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
630	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
650	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
670	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
690	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
710	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

730	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
770	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
790	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
810	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
830	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
850	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
870	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
890	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
910	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
930	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
950	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
970	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
990	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

## EXAMPLE 8-6 DATA

Gas phase data in cell # 11:

Т	Р	GFE	SRL	ENDKR	EXPL	т	TNUM
0.634	1930.7	0	0	0.75	3.702	10225	5.4E-06
1.111	1928.3	0	0	0.75	3.702	10225	6.62E-06
1.581	1931.9	0	0	0.75	3.702	10225	8.31E-06
2.081	1939.6	0	0	0.75	3.702	10225	8.37E-06
2.672	1963.9	6.517	0	0.583	3.224	27663	2.23E-06
3.307	1977.5	6.575	0	0.581	3.22	27818	2.34E-06
4.002	1978.9	6.633	0	0.58	3.216	27975	2.4E-06
4.77	1981.6	6.705	0	0.578	3.21	28166	1.82E-06
5.621	1983.6	6.771	0	0.576	3.205	28345	1.59E-06
6.584	1984.4	6.837	0	0.574	3.201	28521	1.57E-06
7.657	1986.9	6.891	0	0.573	3.197	28665	1.3E-06
8.804	1987.6	6.941	0	0.572	3.193	28799	1.2E-06
10.021	1988.3	6.98	0	0.571	3.19	28903	1.1E-06
11.311	1989.5	7.013	0	0.57	3.188	28991	9.6E-07
12.675	1988.7	7.04	0	0.569	3.186	29063	9.7E-07
14.147	1989.8	7.063	0	0.568	3.184	29125	8.5E-07
15.363	1986.9	7.076	0	0.568	3.183	29161	8.9E-07
16.101	1968.7	7.073	0.09025	0.568	3.183	29153	1.99E-06
16.915	1978.1	7.076	0.19855	0.568	3.183	29159	2.79E-06
18.076	1983.7	7.078	0.2261	0.568	3.183	29165	0.000002
19.783	1986.3	7.079	0.2261	0.568	3.183	29169	1.77E-06

22.222	1988.1	7.081	0.2261	0.568	3.183	29172	1.61E-06
25.809	1989.4	7.082	0.2261	0.568	3.183	29175	1.49E-06
30.013	1990.6	7.083	0.2261	0.568	3.183	29178	1.41E-06
30.124	1986.3	7.082	0.2261	0.568	3.183	29175	1.41E-06
30.491	1977	7.08	0.2261	0.568	3.183	29169	1.7E-06
33.296	1983.8	7.098	0.2261	0.568	3.181	29219	1.12E-06
35.179	1986.5	7.112	0.2261	0.567	3.18	29255	8.3E-07
36.967	1987.6	7.123	0.2261	0.567	3.18	29286	7.1E-07
38.724	1988.1	7.133	0.2261	0.567	3.179	29313	6.5E-07
40.501	1988.3	7.143	0.2261	0.566	3.178	29339	6E-07
42.262	1988.5	7.152	0.2261	0.566	3.177	29362	5.6E-07
43.92	1988.7	7.159	0.2261	0.566	3.177	29382	5.3E-07
45.131	1993.5	7.165	0.2261	0.566	3.177	29398	5.3E-07
46.408	1989.1	7.165	0.2261	0.566	3.176	29399	7.4E-07
47.343	1988.6	7.165	0.2261	0.566	3.176	29398	1.39E-06
53.422	1994.9	7.167	0.27265	0.566	3.176	29402	1.05E-06
60.033	1994.3	7.166	0.27265	0.566	3.176	29402	9.4E-07
60.136	1990.5	7.165	0.27265	0.566	3.176	29399	1.02E-06
60.302	1986.7	7.164	0.27265	0.566	3.177	29397	1.12E-06
60.758	1985.1	7.165	0.27265	0.566	3.177	29397	1.18E-06
61.3	1987.5	7.166	0.27265	0.566	3.176	29401	9.6E-07
61.819	1987	7.167	0.27265	0.566	3.176	29404	7.1E-07
62.335	1986.1	7.168	0.27265	0.566	3.176	29406	5.8E-07
62.783	1985.8	7.169	0.27265	0.566	3.176	29408	5.2E-07
63.2	1985.6	7.17	0.27265	0.566	3.176	29410	5E-07
63.563	1985.5	7.17	0.27265	0.566	3.176	29412	4.8E-07
63.907	1985.2	7.171	0.27265	0.566	3.176	29414	4.7E-07
64.237	1984.9	7.171	0.27265	0.566	3.176	29415	4.5E-07
64.572	1984.4	7.172	0.27265	0.566	3.176	29417	4.4E-07
64.876	1983.9	7.172	0.27265	0.566	3.176	29418	4.2E-07
65.169	1983.1	7.173	0.27265	0.566	3.176	29419	4E-07
65.467	1981.4	7.173	0.27265	0.566	3.176	29419	3.6E-07
65.758	1979.5	7.173	0.27265	0.566	3.176	29419	3.4E-07
66.041	1979.8	7.174	0.27265	0.566	3.176	29421	3.5E-07
66.316	1979.9	7.174	0.27265	0.566	3.176	29423	3.7E-07
66.588	1980	7.175	0.27265	0.566	3.176	29424	3.9E-07
66.858	1980	7.175	0.27265	0.566	3.176	29426	4.2E-07
67.126	1980.1	7.176	0.27265	0.566	3.176	29427	4.4E-07
67.393	1980.1	7.176	0.27265	0.566	3.176	29429	4.3E-07
67.659	1980.2	7.177	0.27265	0.565	3.176	29430	4.3E-07
67.925	1980.2	7.177	0.27265	0.565	3.176	29431	4.2E-07
68.191	1980.2	7.178	0.27265	0.565	3.176	29433	4.2E-07
68.457	1980.3	7.179	0.27265	0.565	3.176	29434	4.2E-07

68.723	1980.2	7.179	0.27265	0.565	3.175	29435	4.1E-07
68.988	1980.2	7.18	0.27265	0.565	3.175	29437	4.2E-07
69.254	1980.2	7.18	0.27265	0.565	3.175	29438	4.2E-07
69.519	1980.3	7.181	0.27265	0.565	3.175	29439	4.2E-07
69.784	1980.3	7.181	0.27265	0.565	3.175	29441	4.2E-07
70.049	1980.3	7.181	0.27265	0.565	3.175	29442	4.2E-07
70.314	1980.3	7.182	0.27265	0.565	3.175	29443	4.1E-07
70.58	1980.3	7.182	0.27265	0.565	3.175	29445	4.1E-07
70.846	1980.4	7.183	0.27265	0.565	3.175	29446	4.1E-07
71.112	1980.4	7.183	0.27265	0.565	3.175	29447	4E-07
71.379	1980.4	7.184	0.27265	0.565	3.175	29448	4E-07
71.646	1980.4	7.184	0.27265	0.565	3.175	29450	4E-07
71.913	1980.4	7.185	0.27265	0.565	3.175	29451	4E-07
72.178	1980.4	7.185	0.27265	0.565	3.175	29452	4E-07
72.442	1980.4	7.186	0.27265	0.565	3.175	29453	4E-07
72.704	1980.4	7.186	0.27265	0.565	3.175	29455	3.9E-07
72.967	1980.4	7.187	0.27265	0.565	3.175	29456	3.9E-07
73.231	1980.4	7.187	0.27265	0.565	3.175	29457	3.9E-07
73.494	1980.4	7.187	0.27265	0.565	3.175	29458	3.9E-07
73.758	1980.3	7.188	0.27265	0.565	3.175	29459	3.9E-07
74.022	1980.3	7.188	0.27265	0.565	3.175	29460	3.9E-07
74.287	1980.3	7.189	0.27265	0.565	3.175	29461	3.9E-07
74.551	1980.3	7.189	0.27265	0.565	3.175	29463	3.9E-07
74.812	1980.3	7.19	0.27265	0.565	3.175	29464	3.9E-07
75.076	1984.4	7.191	0.27265	0.565	3.175	29468	3.4E-07
75.247	1985.6	7.191	0.27265	0.565	3.175	29469	3.4E-07
75.381	1986.8	7.192	0.27265	0.565	3.175	29470	3.3E-07
75.487	1987.8	7.192	0.27265	0.565	3.175	29471	3.4E-07
75.584	1988.5	7.192	0.27265	0.565	3.174	29471	3.3E-07
75.681	1988.9	7.193	0.27265	0.565	3.174	29472	3.4E-07
75.784	1989.1	7.193	0.27265	0.565	3.174	29472	3.6E-07
75.899	1989.1	7.193	0.27265	0.565	3.174	29472	4.1E-07
76.037	1989	7.193	0.27265	0.565	3.174	29472	5.1E-07
76.22	1988.5	7.193	0.27265	0.565	3.174	29472	6.5E-07
76.506	1987.6	7.192	0.27265	0.565	3.175	29471	8.3E-07
77.104	1987.3	7.192	0.27265	0.565	3.175	29471	1.07E-06
78.956	1989	7.193	0.293	0.565	3.174	29472	1.05E-06
84.224	1991.2	7.193	0.295	0.565	3.174	29474	8.7E-07
84.9	1991.4	7.193	0.295	0.565	3.174	29474	8.6E-07
85.686	1991.8	7.193	0.295	0.565	3.174	29474	9E-07
86.026	1991.5	7.193	0.295	0.565	3.174	29474	8.4E-07
86.778	1991.6	7.193	0.295	0.565	3.174	29474	8.4E-07
87.899	1992	7.194	0.295	0.565	3.174	29474	8.6E-07

88.25	1991.7	7.193	0.295	0.565	3.174	29474	8.2E-07
89.553	1992.2	7.194	0.295	0.565	3.174	29474	8.6E-07
90	1992	7.194	0.295	0.565	3.174	29474	8.3E-07

Т	IFT (gas-oil)	SR	PR	E	S	RPERM	S_Max	SR_Max
0.634	0	0	0.75	3.702	0	0	0	0
1.111	0	0	0.75	3.702	0	0	0	0
1.581	0	0	0.75	3.702	0	0	0	0
2.081	0	0	0.75	3.702	0	0	0	0
2.672	5.286	0	0.583	3.224	0.026	0	0.026	0
3.307	4.774	0	0.581	3.22	0.108	0.002	0.108	0
4.002	4.46	0	0.58	3.216	0.158	0.008	0.158	0
4.77	4.177	0	0.578	3.21	0.189	0.015	0.189	0
5.621	3.982	0	0.576	3.205	0.21	0.021	0.21	0
6.584	3.854	0	0.574	3.201	0.228	0.028	0.228	0
7.657	3.788	0	0.573	3.197	0.244	0.034	0.244	0
8.804	3.78	0	0.572	3.193	0.259	0.042	0.259	0
10.021	3.812	0	0.571	3.19	0.273	0.049	0.273	0
11.311	3.873	0	0.57	3.188	0.285	0.057	0.285	0
12.675	3.965	0	0.569	3.186	0.297	0.064	0.297	0
14.147	4.057	0	0.568	3.184	0.307	0.072	0.307	0
15.363	4.151	0	0.568	3.183	0.315	0.078	0.315	0
16.101	4.268	0.09	0.568	3.183	0.291	0.031	0.315	0.238
16.915	4.23	0.194	0.568	3.183	0.24	0.001	0.315	0.238
18.076	4.213	0.225	0.568	3.183	0.237	0	0.315	0.238
19.783	4.213	0.226	0.568	3.183	0.237	0	0.315	0.238
22.222	4.218	0.227	0.568	3.183	0.236	0	0.315	0.238
25.809	4.227	0.228	0.568	3.183	0.236	0	0.315	0.238
30.013	4.234	0.228	0.568	3.183	0.236	0	0.315	0.238
30.124	4.257	0.228	0.568	3.183	0.237	0	0.315	0.238
30.491	4.311	0.226	0.568	3.183	0.243	0	0.315	0.238
33.296	4.373	0.23	0.568	3.181	0.364	0.025	0.364	0.238
35.179	4.445	0.232	0.567	3.18	0.389	0.042	0.389	0.238
36.967	4.521	0.233	0.567	3.18	0.405	0.057	0.405	0.238
38.724	4.599	0.233	0.567	3.179	0.416	0.07	0.416	0.238
40.501	4.679	0.234	0.566	3.178	0.426	0.082	0.426	0.238
42.262	4.757	0.234	0.566	3.177	0.435	0.094	0.435	0.238
43.92	4.828	0.234	0.566	3.177	0.442	0.105	0.442	0.238
45.131	4.853	0.234	0.566	3.177	0.446	0.113	0.446	0.238
46.408	4.901	0.233	0.566	3.176	0.442	0.105	0.449	0.238
47.343	4.907	0.228	0.566	3.176	0.365	0.026	0.449	0.29
53.422	4.872	0.279	0.566	3.176	0.289	0	0.449	0.29
60.033	4.875	0.279	0.566	3.176	0.289	0	0.449	0.29
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60.136	4.896	0.279	0.566	3.176	0.291	0	0.449	0.29
60.302	4.918	0.278	0.566	3.177	0.294	0	0.449	0.29
60.758	4.933	0.278	0.566	3.177	0.323	0.001	0.449	0.29
61.3	4.93	0.279	0.566	3.176	0.367	0.011	0.449	0.29
61.819	4.946	0.281	0.566	3.176	0.39	0.022	0.449	0.29
62.335	4.963	0.282	0.566	3.176	0.403	0.033	0.449	0.29
62.783	4.976	0.283	0.566	3.176	0.412	0.042	0.449	0.29
63.2	4.988	0.283	0.566	3.176	0.419	0.05	0.449	0.29
63.563	4.997	0.283	0.566	3.176	0.423	0.057	0.449	0.29
63.907	5.008	0.283	0.566	3.176	0.427	0.064	0.449	0.29
64.237	5.018	0.283	0.566	3.176	0.431	0.07	0.449	0.29
64.572	5.03	0.284	0.566	3.176	0.434	0.076	0.449	0.29
64.876	5.041	0.284	0.566	3.176	0.436	0.082	0.449	0.29
65.169	5.054	0.284	0.566	3.176	0.438	0.088	0.449	0.29
65.467	5.072	0.284	0.566	3.176	0.439	0.094	0.449	0.29
65.758	5.091	0.284	0.566	3.176	0.439	0.102	0.449	0.29
66.041	5.098	0.284	0.566	3.176	0.439	0.102	0.449	0.29
66.316	5.105	0.284	0.566	3.176	0.439	0.103	0.449	0.29
66.588	5.112	0.284	0.566	3.176	0.44	0.105	0.449	0.29
66.858	5.12	0.284	0.566	3.176	0.441	0.107	0.449	0.29
67.126	5.127	0.283	0.566	3.176	0.442	0.111	0.449	0.29
67.393	5.135	0.284	0.566	3.176	0.444	0.114	0.449	0.29
67.659	5.142	0.284	0.565	3.176	0.445	0.117	0.449	0.29
67.925	5.15	0.284	0.565	3.176	0.446	0.12	0.449	0.29
68.191	5.158	0.284	0.565	3.176	0.448	0.123	0.449	0.29
68.457	5.165	0.284	0.565	3.176	0.449	0.125	0.449	0.29
68.723	5.174	0.284	0.565	3.175	0.45	0.128	0.45	0.29
68.988	5.181	0.284	0.565	3.175	0.451	0.131	0.451	0.29
69.254	5.189	0.284	0.565	3.175	0.453	0.133	0.453	0.29
69.519	5.197	0.284	0.565	3.175	0.454	0.136	0.454	0.29
69.784	5.205	0.284	0.565	3.175	0.455	0.14	0.455	0.29
70.049	5.212	0.284	0.565	3.175	0.457	0.143	0.457	0.29
70.314	5.22	0.284	0.565	3.175	0.458	0.146	0.458	0.29
70.58	5.228	0.284	0.565	3.175	0.46	0.15	0.46	0.29
70.846	5.236	0.284	0.565	3.175	0.461	0.153	0.461	0.29
71.112	5.244	0.284	0.565	3.175	0.462	0.155	0.462	0.29
71.379	5.252	0.284	0.565	3.175	0.463	0.158	0.463	0.29
71.646	5.26	0.284	0.565	3.175	0.465	0.161	0.465	0.29
71.913	5.268	0.284	0.565	3.175	0.466	0.163	0.466	0.29
72.178	5.277	0.284	0.565	3.175	0.467	0.166	0.467	0.29
72.442	5.285	0.284	0.565	3.175	0.468	0.168	0.468	0.29
72.704	5.293	0.284	0.565	3.175	0.469	0.171	0.469	0.29

72.967	5.301	0.284	0.565	3.175	0.47	0.173	0.47	0.29
73.231	5.309	0.284	0.565	3.175	0.471	0.175	0.471	0.29
73.494	5.317	0.284	0.565	3.175	0.471	0.177	0.471	0.29
73.758	5.326	0.284	0.565	3.175	0.472	0.179	0.472	0.29
74.022	5.335	0.284	0.565	3.175	0.473	0.181	0.473	0.29
74.287	5.343	0.284	0.565	3.175	0.474	0.183	0.474	0.29
74.551	5.352	0.284	0.565	3.175	0.475	0.185	0.475	0.29
74.812	5.36	0.284	0.565	3.175	0.476	0.187	0.476	0.29
75.076	5.343	0.284	0.565	3.175	0.476	0.189	0.476	0.29
75.247	5.338	0.284	0.565	3.175	0.477	0.189	0.477	0.29
75.381	5.333	0.284	0.565	3.175	0.477	0.19	0.477	0.29
75.487	5.328	0.284	0.565	3.175	0.477	0.19	0.477	0.29
75.584	5.325	0.284	0.565	3.174	0.477	0.189	0.477	0.29
75.681	5.324	0.284	0.565	3.174	0.476	0.189	0.477	0.29
75.784	5.324	0.284	0.565	3.174	0.476	0.187	0.477	0.29
75.899	5.325	0.284	0.565	3.174	0.474	0.183	0.477	0.29
76.037	5.328	0.283	0.565	3.174	0.471	0.174	0.477	0.29
76.22	5.332	0.282	0.565	3.174	0.464	0.154	0.477	0.29
76.506	5.339	0.28	0.565	3.175	0.443	0.106	0.477	0.297
77.104	5.342	0.278	0.565	3.175	0.389	0.03	0.477	0.297
78.956	5.334	0.279	0.565	3.174	0.333	0.003	0.477	0.297
84.224	5.322	0.28	0.565	3.174	0.315	0.001	0.477	0.297
84.9	5.321	0.28	0.565	3.174	0.314	0.001	0.477	0.297
85.686	5.318	0.28	0.565	3.174	0.313	0.001	0.477	0.297
86.026	5.32	0.28	0.565	3.174	0.313	0.001	0.477	0.297
86.778	5.32	0.28	0.565	3.174	0.312	0.001	0.477	0.297
87.899	5.317	0.28	0.565	3.174	0.311	0.001	0.477	0.297
88.25	5.319	0.28	0.565	3.174	0.31	0	0.477	0.297
89.553	5.316	0.28	0.565	3.174	0.309	0	0.477	0.297
90	5.317	0.28	0.565	3.174	0.309	0	0.477	0.297

# Capillary pressure data in cell #11:

			IFT	IFT	IFT	CAP	CAP		
Т	I	P 2	(1&2)	(1&3)	(2&3)	(1&2)	(2&3)	SN 2	SN 3
0.451	11	1932.2	42	24	17.36	-10.6715	2.2845	0.42	0.58
0.767	11	1945	42	24	17.231	-10.76	2.2845	0.41	0.59
1.028	11	1948.6	42	24	17.133	-10.8075	2.2845	0.41	0.59
1.259	11	1948.6	42	24	17.035	-10.8395	2.2845	0.41	0.59
1.51	11	1948.1	42	24	16.894	-10.8695	2.2845	0.41	0.59
1.784	11	1947.9	42	24	16.664	-10.9035	2.2845	0.4	0.6
2.063	11	1948.3	42	24	16.315	-10.9465	2.2845	0.4	0.6

2.349	11	1949.6	42	24	15.813	-11.004	2.2845	0.4	0.6
2.652	11	1951.9	42	24	15.131	-11.079	2.2845	0.39	0.61
2.986	11	1967.9	42	24	5.314	-11.012	2.242	0.38	0.59
3.393	11	1976.3	42	24	4.958	-11.362	2.228	0.35	0.52
3.99	11	1981.1	42	24	4.66	-11.835	2.247	0.33	0.45
4.711	11	1980.5	42	24	4.405	-12.286	2.245	0.3	0.41
5.542	11	1982.7	42	24	4.155	-12.6335	2.2025	0.29	0.38
6.499	11	1984.2	42	24	3.975	-12.9035	2.1695	0.27	0.35
7.578	11	1985.6	42	24	3.852	-13.1715	2.1635	0.26	0.33
8.823	11	1986.5	42	24	3.796	-13.418	2.1915	0.25	0.32
10.255	11	1987.4	42	24	3.79	-13.669	2.257	0.24	0.3
11.846	11	1987	42	24	3.839	-13.904	2.3545	0.24	0.28
13.483	11	1988.1	42	24	3.91	-14.1145	2.4675	0.23	0.26
14.968	11	1988.4	42	24	3.994	-14.287	2.583	0.22	0.25
15.598	11	1987.3	42	24	4.024	-14.286	2.594	0.22	0.25
16.128	11	1982	42	24	4.067	-13.6625	2.602	0.24	0.25
16.729	11	1990.3	42	24	4.034	-11.8595	2.5025	0.41	0.34
17.473	11	1999.4	42	24	3.996	-11.182	2.5085	0.53	0.37
18.398	11	2001.3	42	24	3.996	-10.915	2.5595	0.58	0.37
19.555	11	2002.1	42	24	4.002	-10.706	2.608	0.62	0.36
21.005	11	2003	42	24	4.007	-10.5235	2.6835	0.64	0.34
22.819	11	2003.6	42	24	4.014	-10.362	2.763	0.66	0.32
25.015	11	2004.3	42	24	4.021	-10.2175	2.842	0.67	0.3
27.791	11	2004.4	42	24	4.032	-10.084	2.931	0.69	0.29
30.025	11	2004.6	42	24	4.038	-9.9985	2.9945	0.7	0.28
30.129	11	2000.8	42	24	4.058	-10.013	3.0195	0.7	0.28
30.338	11	1995.4	42	24	4.088	-10.0445	3.059	0.69	0.28
31.056	11	1988.6	42	24	4.135	-10.609	3.1695	0.62	0.27
31.562	11	1989.4	42	24	4.145	-11.3915	3.242	0.54	0.26
32.017	11	1989	42	24	4.16	-11.9995	3.358	0.49	0.26
32.415	11	1988.5	42	24	4.174	-12.402	3.4155	0.46	0.25
32.771	11	1987.9	42	24	4.188	-12.6965	3.4625	0.44	0.25
33.1	11	1987.4	42	24	4.201	-12.931	3.502	0.43	0.24
33.408	11	1986.9	42	24	4.213	-13.125	3.5365	0.42	0.24
33.7	11	1986.4	42	24	4.224	-13.292	3.5675	0.41	0.24
33.98	11	1986	42	24	4.235	-13.44	3.596	0.4	0.24
34.253	11	1985.8	42	24	4.244	-13.574	3.6215	0.39	0.23
34.516	11	1985.8	42	24	4.252	-13.6965	3.6445	0.38	0.23
34.771	11	1985.7	42	24	4.26	-13.81	3.6665	0.38	0.23
35.021	11	1985.7	42	24	4.268	-13.917	3.688	0.37	0.23
35.265	11	1985.7	42	24	4.276	-14.0175	3.709	0.37	0.23
35.506	11	1985.7	42	24	4.283	-14.1135	3.73	0.36	0.22
35.744	11	1985.6	42	24	4.291	-14.2055	3.75	0.36	0.22

35.979	11	1985.6	42	24	4.299	-14.2935	3.77	0.35	0.22
36.213	11	1985.6	42	24	4.307	-14.3785	3.7905	0.35	0.22
36.446	11	1985.6	42	24	4.315	-14.4615	3.8105	0.35	0.22
36.679	11	1985.5	42	24	4.323	-14.5415	3.8305	0.34	0.22
36.911	11	1985.5	42	24	4.331	-14.6195	3.851	0.34	0.22
37.14	11	1985.5	42	24	4.34	-14.695	3.871	0.34	0.21
37.368	11	1985.5	42	24	4.348	-14.7685	3.891	0.33	0.21
37.595	11	1985.4	42	24	4.356	-14.84	3.9115	0.33	0.21
37.823	11	1985.5	42	24	4.365	-14.91	3.932	0.33	0.21
38.051	11	1985.5	42	24	4.373	-14.9785	3.952	0.32	0.21
38.278	11	1985.5	42	24	4.381	-15.0455	3.9725	0.32	0.21
38.504	11	1985.5	42	24	4.39	-15.1105	3.993	0.32	0.21
38.731	11	1985.4	42	24	4.398	-15.175	4.0135	0.32	0.2
38.96	11	1985.3	42	24	4.408	-15.239	4.035	0.31	0.2
39.192	11	1985.2	42	24	4.417	-15.3025	4.057	0.31	0.2
39.421	11	1985.2	42	24	4.426	-15.3645	4.0785	0.31	0.2
39.648	11	1985.2	42	24	4.435	-15.424	4.1	0.31	0.2
39.871	11	1985.4	42	24	4.443	-15.482	4.121	0.3	0.2
40.086	11	1985.5	42	24	4.451	-15.5365	4.141	0.3	0.2
40.307	11	1985.6	42	24	4.459	-15.5915	4.1615	0.3	0.2
40.523	11	1985.6	42	24	4.467	-15.6445	4.1815	0.3	0.19
40.736	11	1985.6	42	24	4.475	-15.696	4.201	0.3	0.19
40.948	11	1985.5	42	24	4.484	-15.746	4.221	0.29	0.19
41.159	11	1985.4	42	24	4.493	-15.796	4.241	0.29	0.19
41.369	11	1985.4	42	24	4.501	-15.8445	4.2615	0.29	0.19
41.578	11	1985.4	42	24	4.509	-15.892	4.2815	0.29	0.19
41.785	11	1985.4	42	24	4.517	-15.939	4.3015	0.29	0.19
41.99	11	1985.4	42	24	4.525	-15.9845	4.321	0.29	0.19
42.193	11	1985.3	42	24	4.534	-16.029	4.341	0.28	0.19
42.397	11	1985.3	42	24	4.542	-16.0735	4.361	0.28	0.19
42.601	11	1985.3	42	24	4.55	-16.117	4.381	0.28	0.18
42.805	11	1985.2	42	24	4.559	-16.1605	4.4015	0.28	0.18
43.012	11	1985.1	42	24	4.568	-16.204	4.4225	0.28	0.18
43.219	11	1985.2	42	24	4.576	-16.247	4.4435	0.28	0.18
43.421	11	1985.4	42	24	4.582	-16.288	4.463	0.27	0.18
43.616	11	1985.5	42	24	4.589	-16.327	4.482	0.27	0.18
43.808	11	1985.6	42	24	4.596	-16.3655	4.5	0.27	0.18
43.998	11	1985.6	42	24	4.603	-16.403	4.518	0.27	0.18
44.188	11	1985.5	42	24	4.611	-16.44	4.536	0.27	0.18
44.381	11	1985.4	42	24	4.619	-16.4775	4.5545	0.27	0.18
44.577	11	1985.2	42	24	4.627	-16.515	4.574	0.27	0.17
44.78	11	1985	42	24	4.636	-16.5535	4.595	0.27	0.17
44.988	11	1984.9	42	24	4.645	-16.593	4.617	0.26	0.17

45.283	11	1991.1	42	24	4.618	-16.619	4.6035	0.26	0.17
45.442	11	1993.8	42	24	4.606	-16.604	4.5595	0.26	0.17
45.561	11	1995.8	42	24	4.598	-16.569	4.5505	0.27	0.17
45.668	11	1997.3	42	24	4.592	-16.5115	4.5435	0.27	0.17
45.774	11	1998.5	42	24	4.587	-16.4255	4.5375	0.27	0.17
45.883	11	1999.5	42	24	4.584	-16.297	4.5325	0.27	0.17
46.002	11	2000.2	42	24	4.582	-16.1045	4.5285	0.28	0.17
46.138	11	2000.7	42	24	4.581	-15.816	4.5245	0.29	0.17
46.302	11	2000.8	42	24	4.583	-15.3815	4.521	0.3	0.17
46.512	11	2000.7	42	24	4.585	-14.729	4.517	0.33	0.17
46.807	11	2000.3	42	24	4.589	-13.7815	4.5105	0.37	0.17
47.265	11	2000.1	42	24	4.593	-12.5385	4.4975	0.44	0.17
48.069	11	2000.8	42	24	4.591	-11.2735	4.476	0.54	0.17
49.771	11	2001.6	42	24	4.59	-10.292	4.468	0.65	0.17
58.45	11	2006.7	42	24	4.567	-9.9075	4.4915	0.79	0.18
60.057	11	2005.1	42	24	4.577	-9.905	4.5145	0.79	0.18
60.142	11	2002.4	42	24	4.592	-9.92	4.535	0.79	0.18
60.257	11	1999.6	42	24	4.607	-9.9405	4.5535	0.78	0.18
60.434	11	1996.5	42	24	4.625	-10.001	4.58	0.77	0.18
60.774	11	1994.3	42	24	4.641	-10.3215	4.6275	0.72	0.18
61.09	11	1995.1	42	24	4.642	-10.862	4.6585	0.66	0.18
61.332	11	1995.6	42	24	4.644	-11.3285	4.686	0.61	0.18
61.544	11	1995.6	42	24	4.649	-11.7	4.7175	0.57	0.18
61.74	11	1995.5	42	24	4.654	-11.9955	4.7495	0.55	0.18
61.925	11	1995.3	42	24	4.658	-12.2385	4.7795	0.53	0.18
62.102	11	1995.1	42	24	4.663	-12.446	4.807	0.51	0.18
62.275	11	1994.9	42	24	4.669	-12.629	4.832	0.5	0.17
62.444	11	1994.6	42	24	4.674	-12.7935	4.8555	0.49	0.17
62.611	11	1994.4	42	24	4.679	-12.9435	4.878	0.48	0.17
62.777	11	1994.1	42	24	4.684	-13.0825	4.899	0.47	0.17
62.942	11	1993.8	42	24	4.69	-13.2125	4.9195	0.46	0.17
63.108	11	1993.5	42	24	4.695	-13.3355	4.9395	0.45	0.17
63.274	11	1993.2	42	24	4.7	-13.452	4.959	0.44	0.17
63.441	11	1993	42	24	4.705	-13.564	4.9775	0.44	0.17
63.609	11	1992.7	42	24	4.711	-13.671	4.996	0.43	0.17
63.775	11	1992.5	42	24	4.716	-13.772	5.014	0.42	0.17
63.938	11	1992.2	42	24	4.721	-13.867	5.031	0.42	0.17
64.098	11	1992	42	24	4.726	-13.957	5.048	0.41	0.17
64.255	11	1991.7	42	24	4.73	-14.042	5.064	0.41	0.17
64.41	11	1991.5	42	24	4.735	-14.123	5.079	0.4	0.16
64.562	11	1991.3	42	24	4.739	-14.2	5.094	0.4	0.16
64.712	11	1991.1	42	24	4.744	-14.2735	5.109	0.4	0.16
64.86	11	1990.8	42	24	4.748	-14.3445	5.123	0.39	0.16

65.001	11	1990.8	42	24	4.752	-14.4105	5.1295	0.39	0.16
65.146	11	1990.5	42	24	4.756	-14.4755	5.15	0.39	0.16
65.29	11	1990.3	42	24	4.76	-14.5395	5.163	0.38	0.16
65.433	11	1990.1	42	24	4.764	-14.601	5.176	0.38	0.16
65.574	11	1990	42	24	4.768	-14.6605	5.1885	0.38	0.16
65.714	11	1989.8	42	24	4.772	-14.7185	5.201	0.37	0.16
65.853	11	1989.7	42	24	4.775	-14.7745	5.213	0.37	0.16
65.99	11	1989.7	42	24	4.778	-14.8285	5.2245	0.37	0.16
66.125	11	1989.6	42	24	4.781	-14.8815	5.2355	0.37	0.16
66.26	11	1989.5	42	24	4.784	-14.933	5.2465	0.36	0.16
66.393	11	1989.5	42	24	4.787	-14.983	5.2575	0.36	0.16
66.525	11	1989.4	42	24	4.79	-15.0315	5.2685	0.36	0.16
66.656	11	1989.2	42	24	4.794	-15.0795	5.279	0.36	0.16
66.787	11	1989.1	42	24	4.797	-15.126	5.2895	0.35	0.16
66.916	11	1989	42	24	4.8	-15.1715	5.3	0.35	0.16
67.045	11	1988.9	42	24	4.803	-15.2165	5.3105	0.35	0.16
67.173	11	1988.8	42	24	4.806	-15.261	5.321	0.35	0.16
67.301	11	1988.7	42	24	4.809	-15.3045	5.331	0.35	0.15
67.428	11	1988.6	42	24	4.812	-15.347	5.341	0.35	0.15
67.554	11	1988.5	42	24	4.815	-15.389	5.351	0.34	0.15
67.68	11	1988.4	42	24	4.818	-15.43	5.3605	0.34	0.15
67.805	11	1988.3	42	24	4.821	-15.47	5.3705	0.34	0.15
67.93	11	1988.2	42	24	4.824	-15.5085	5.4165	0.34	0.15
68.054	11	1988.1	42	24	4.826	-15.5465	5.426	0.34	0.15
68.178	11	1988	42	24	4.829	-15.5835	5.435	0.34	0.15
68.301	11	1988	42	24	4.832	-15.62	5.4445	0.33	0.15
68.424	11	1987.9	42	24	4.834	-15.656	5.4535	0.33	0.15
68.547	11	1987.8	42	24	4.837	-15.6915	5.4625	0.33	0.15
68.669	11	1987.8	42	24	4.84	-15.727	5.4715	0.33	0.15
68.79	11	1987.7	42	24	4.842	-15.7615	5.4805	0.33	0.15
68.912	11	1987.6	42	24	4.845	-15.7955	5.4895	0.33	0.15
69.033	11	1987.6	42	24	4.847	-15.8295	5.498	0.33	0.15
69.153	11	1987.5	42	24	4.85	-15.863	5.507	0.32	0.15
69.273	11	1987.5	42	24	4.852	-15.8955	5.5155	0.32	0.15
69.391	11	1987.4	42	24	4.854	-15.9275	5.524	0.32	0.15
69.507	11	1987.4	42	24	4.857	-15.959	5.532	0.32	0.15
69.622	11	1987.4	42	24	4.859	-15.9895	5.54	0.32	0.15
69.735	11	1987.3	42	24	4.861	-16.0195	5.548	0.32	0.15
69.846	11	1987.3	42	24	4.863	-16.049	5.5555	0.32	0.15
69.957	11	1987.3	42	24	4.865	-16.0775	5.563	0.32	0.15
70.065	11	1987.3	42	24	4.867	-16.1055	5.57	0.31	0.15
70.172	11	1987.3	42	24	4.868	-16.133	5.577	0.31	0.15
70.277	11	1987.4	42	24	4.87	-16.1595	5.584	0.31	0.15

70.38	11	1987.4	42	24	4.871	-16.1865	5.5905	0.31	0.15
70.482	11	1987.4	42	24	4.873	-16.2125	5.597	0.31	0.15
70.583	11	1987.5	42	24	4.874	-16.2375	5.603	0.31	0.15
70.681	11	1987.6	42	24	4.876	-16.2625	5.609	0.31	0.15
70.778	11	1987.7	42	24	4.877	-16.2865	5.6145	0.31	0.15
70.873	11	1987.8	42	24	4.878	-16.3095	5.62	0.31	0.15
70.966	11	1987.9	42	24	4.879	-16.3325	5.625	0.31	0.15
71.056	11	1988	42	24	4.879	-16.3545	5.6295	0.31	0.15
71.145	11	1988.1	42	24	4.88	-16.3755	5.6345	0.3	0.15
71.231	11	1988.3	42	24	4.881	-16.396	5.6385	0.3	0.14
71.315	11	1988.5	42	24	4.881	-16.416	5.6425	0.3	0.14
71.396	11	1988.6	42	24	4.881	-16.435	5.646	0.3	0.14
71.474	11	1988.9	42	24	4.881	-16.453	5.6495	0.3	0.14
71.547	11	1989.1	42	24	4.881	-16.47	5.652	0.3	0.14
71.618	11	1989.3	42	24	4.881	-16.4865	5.655	0.3	0.14
71.687	11	1989.6	42	24	4.881	-16.502	5.657	0.3	0.14
71.753	11	1989.8	42	24	4.88	-16.517	5.659	0.3	0.14
71.818	11	1990.1	42	24	4.88	-16.5315	5.661	0.3	0.14
71.879	11	1990.4	42	24	4.879	-16.5455	5.6625	0.3	0.14
71.939	11	1990.7	42	24	4.878	-16.559	5.6635	0.3	0.14
71.998	11	1991	42	24	4.877	-16.572	5.6645	0.3	0.14
72.058	11	1991.4	42	24	4.876	-16.585	5.665	0.3	0.14
72.116	11	1991.8	42	24	4.874	-16.598	5.665	0.3	0.14
72.174	11	1992.2	42	24	4.873	-16.611	5.6655	0.3	0.14
72.231	11	1992.5	42	24	4.872	-16.6235	5.6665	0.3	0.14
72.289	11	1992.8	42	24	4.871	-16.636	5.667	0.3	0.14
72.348	11	1993.2	42	24	4.87	-16.649	5.668	0.29	0.14
72.406	11	1993.5	42	24	4.869	-16.6615	5.6685	0.29	0.14
72.463	11	1993.8	42	24	4.868	-16.674	5.6695	0.29	0.14
72.518	11	1994.1	42	24	4.867	-16.686	5.671	0.29	0.14
72.573	11	1994.3	42	24	4.867	-16.698	5.672	0.29	0.14
72.627	11	1994.6	42	24	4.866	-16.7095	5.673	0.29	0.14
72.68	11	1994.9	42	24	4.865	-16.721	5.674	0.29	0.14
72.732	11	1995.1	42	24	4.864	-16.732	5.675	0.29	0.14
72.783	11	1995.4	42	24	4.864	-16.7435	5.6755	0.29	0.14
72.833	11	1995.7	42	24	4.863	-16.754	5.676	0.29	0.14
72.883	11	1995.9	42	24	4.862	-16.765	5.677	0.29	0.14
72.933	11	1996.2	42	24	4.861	-16.776	5.6775	0.29	0.14
72.983	11	1996.5	42	24	4.86	-16.7865	5.6785	0.29	0.14
73.033	11	1996.7	42	24	4.86	-16.7975	5.6795	0.29	0.14
73.084	11	1997	42	24	4.859	-16.8085	5.68	0.29	0.14
73.134	11	1997.2	42	24	4.858	-16.819	5.681	0.29	0.14
73.184	11	1997.4	42	24	4.858	-16.83	5.682	0.29	0.14

73.232	11	1997.6	42	24	4.857	-16.8405	5.683	0.29	0.14
73.28	11	1997.9	42	24	4.857	-16.851	5.684	0.29	0.14
73.327	11	1998.1	42	24	4.856	-16.861	5.6845	0.29	0.14
73.374	11	1998.3	42	24	4.855	-16.8715	5.6855	0.29	0.14
73.42	11	1998.5	42	24	4.855	-16.8815	5.6865	0.29	0.14
73.466	11	1998.7	42	24	4.854	-16.8915	5.687	0.29	0.14
73.51	11	1998.9	42	24	4.854	-16.901	5.6875	0.29	0.14
73.554	11	1999.2	42	24	4.853	-16.9105	5.688	0.29	0.14
73.599	11	1999.4	42	24	4.852	-16.9205	5.689	0.29	0.14
73.643	11	1999.6	42	24	4.852	-16.93	5.6895	0.29	0.14
73.686	11	1999.9	42	24	4.851	-16.9395	5.6895	0.29	0.14
73.729	11	2000.1	42	24	4.85	-16.949	5.6895	0.28	0.14
73.772	11	2000.4	42	24	4.849	-16.9585	5.69	0.28	0.14
73.815	11	2000.6	42	24	4.848	-16.9685	5.691	0.28	0.14
73.858	11	2000.8	42	24	4.848	-16.978	5.692	0.28	0.14
73.902	11	2001	42	24	4.847	-16.9875	5.6925	0.28	0.14
73.945	11	2001.2	42	24	4.847	-16.9975	5.6935	0.28	0.14
73.989	11	2001.3	42	24	4.846	-17.007	5.6945	0.28	0.14
74.032	11	2001.5	42	24	4.846	-17.017	5.6955	0.28	0.14
74.074	11	2001.7	42	24	4.846	-17.0265	5.6965	0.28	0.14
74.116	11	2001.8	42	24	4.845	-17.036	5.6975	0.28	0.14
74.157	11	2002	42	24	4.845	-17.0455	5.699	0.28	0.14
74.198	11	2002.1	42	24	4.845	-17.055	5.7	0.28	0.14
74.238	11	2002.2	42	24	4.845	-17.0645	5.701	0.28	0.14
74.278	11	2002.3	42	24	4.844	-17.0735	5.7025	0.28	0.14
74.317	11	2002.5	42	24	4.844	-17.083	5.7035	0.28	0.14
74.356	11	2002.6	42	24	4.844	-17.092	5.705	0.28	0.14
74.395	11	2002.7	42	24	4.844	-17.101	5.706	0.28	0.14
74.433	11	2002.8	42	24	4.844	-17.11	5.707	0.28	0.14
74.471	11	2002.9	42	24	4.844	-17.119	5.7085	0.28	0.14
74.509	11	2003	42	24	4.843	-17.128	5.7095	0.28	0.14
74.546	11	2003.1	42	24	4.843	-17.137	5.711	0.28	0.14
74.583	11	2003.2	42	24	4.843	-17.1455	5.712	0.28	0.14
74.619	11	2003.3	42	24	4.843	-17.1545	5.713	0.28	0.14
74.656	11	2003.4	42	24	4.843	-17.1635	5.7145	0.28	0.14
74.692	11	2003.5	42	24	4.843	-17.172	5.7155	0.28	0.14
74.728	11	2003.6	42	24	4.843	-17.1805	5.717	0.28	0.14
74.763	11	2003.7	42	24	4.843	-17.1895	5.7185	0.28	0.14
74.799	11	2003.7	42	24	4.843	-17.198	5.7195	0.28	0.14
74.834	11	2003.8	42	24	4.843	-17.2065	5.721	0.28	0.14
74.869	11	2003.9	42	24	4.843	-17.215	5.722	0.28	0.14
74.904	11	2003.9	42	24	4.843	-17.2235	5.7235	0.28	0.14
74.938	11	2004	42	24	4.843	-17.232	5.725	0.28	0.14

74.973	11	2004.1	42	24	4.843	-17.2405	5.726	0.28	0.14
75.006	11	2004.2	42	24	4.843	-17.249	5.7265	0.28	0.14
75.039	11	2005.1	42	24	4.838	-17.257	5.717	0.27	0.14
75.071	11	2006.4	42	24	4.832	-17.2645	5.707	0.27	0.14
75.102	11	2007.5	42	24	4.825	-17.271	5.6975	0.27	0.14
75.131	11	2008.7	42	24	4.819	-17.2765	5.6895	0.27	0.14
75.16	11	2009.7	42	24	4.814	-17.282	5.682	0.27	0.14
75.188	11	2010.6	42	24	4.809	-17.2865	5.676	0.27	0.14
75.215	11	2011.3	42	24	4.805	-17.291	5.671	0.27	0.14
75.242	11	2012	42	24	4.802	-17.2945	5.667	0.27	0.14
75.269	11	2012.6	42	24	4.799	-17.298	5.6635	0.27	0.14
75.295	11	2013.1	42	24	4.796	-17.301	5.661	0.27	0.14
75.322	11	2013.5	42	24	4.794	-17.3035	5.6585	0.27	0.14
75.348	11	2013.9	42	24	4.792	-17.3055	5.6565	0.27	0.14
75.375	11	2014.3	42	24	4.791	-17.3075	5.6555	0.27	0.14
75.401	11	2014.6	42	24	4.789	-17.3085	5.6545	0.27	0.14
75.428	11	2014.8	42	24	4.788	-17.3095	5.6535	0.27	0.14
75.455	11	2015	42	24	4.787	-17.31	5.653	0.27	0.14
75.481	11	2015.2	42	24	4.787	-17.31	5.653	0.27	0.14
75.509	11	2015.4	42	24	4.786	-17.3095	5.653	0.27	0.14
75.536	11	2015.6	42	24	4.785	-17.3085	5.6195	0.27	0.14
75.564	11	2015.7	42	24	4.785	-17.307	5.62	0.27	0.14
75.592	11	2015.7	42	24	4.785	-17.305	5.6205	0.27	0.14
75.62	11	2015.8	42	24	4.785	-17.3015	5.621	0.27	0.14
75.649	11	2015.8	42	24	4.785	-17.2975	5.622	0.27	0.14
75.679	11	2015.8	42	24	4.785	-17.2925	5.623	0.27	0.14
75.709	11	2015.8	42	24	4.786	-17.286	5.6245	0.27	0.14
75.74	11	2015.8	42	24	4.786	-17.278	5.626	0.27	0.14
75.771	11	2015.7	42	24	4.787	-17.2685	5.627	0.27	0.14
75.804	11	2015.7	42	24	4.788	-17.2565	5.629	0.27	0.14
75.838	11	2015.6	42	24	4.788	-17.243	5.6305	0.28	0.14
75.872	11	2015.5	42	24	4.789	-17.2265	5.632	0.28	0.14
75.908	11	2015.4	42	24	4.79	-17.2065	5.634	0.28	0.14
75.946	11	2015.3	42	24	4.791	-17.183	5.6355	0.28	0.14
75.985	11	2015.1	42	24	4.793	-17.155	5.6375	0.28	0.14
76.026	11	2015	42	24	4.794	-17.121	5.6395	0.28	0.14
76.069	11	2014.8	42	24	4.795	-17.08	5.6415	0.28	0.14
76.114	11	2014.6	42	24	4.797	-17.0305	5.6435	0.28	0.14
76.163	11	2014.3	42	24	4.799	-16.971	5.646	0.28	0.14
76.214	11	2014.1	42	24	4.801	-16.8985	5.648	0.28	0.14
76.27	11	2013.8	42	24	4.803	-16.8105	5.65	0.29	0.14
76.33	11	2013.5	42	24	4.805	-16.703	5.652	0.29	0.14
76.396	11	2013.1	42	24	4.807	-16.5715	5.654	0.29	0.14

76.468	11	2012.7	42	24	4.81	-16.4095	5.656	0.3	0.14
76.55	11	2012.3	42	24	4.813	-16.2095	5.6575	0.31	0.14
76.642	11	2011.8	42	24	4.817	-15.961	5.659	0.32	0.14
76.749	11	2011.3	42	24	4.82	-15.6515	5.66	0.33	0.14
76.875	11	2010.7	42	24	4.825	-15.266	5.6605	0.34	0.14
77.029	11	2010	42	24	4.829	-14.787	5.6595	0.36	0.14
77.222	11	2009.2	42	24	4.835	-14.1975	5.6565	0.39	0.14
77.477	11	2008.3	42	24	4.841	-13.4865	5.6505	0.43	0.14
77.835	11	2007.2	42	24	4.848	-12.6675	5.639	0.49	0.14
78.379	11	2006.2	42	24	4.855	-11.8125	5.62	0.55	0.14
79.292	11	2006	42	24	4.857	-11.0775	5.6035	0.63	0.14
80.908	11	2006.1	42	24	4.859	-10.593	5.609	0.68	0.14
83.857	11	2006.8	42	24	4.856	-10.2805	5.639	0.72	0.14
84.9	11	2007	42	24	4.855	-10.2215	5.648	0.73	0.14
85.686	11	2007.2	42	24	4.855	-10.189	5.6545	0.74	0.14
86.026	11	2007.4	42	24	4.854	-10.1445	5.664	0.74	0.14
86.778	11	2007.5	42	24	4.853	-10.109	5.674	0.75	0.14
87.899	11	2007.6	42	24	4.853	-10.1	5.6765	0.75	0.14
88.25	11	2007.8	42	24	4.852	-10.066	5.684	0.75	0.13
89.553	11	2007.9	42	24	4.851	-10.0535	5.685	0.76	0.13

## EXAMPLE 8-7 DATA

Results after N<sub>2</sub> flooding:

X (ft)	S_oil	S_gas	S_aqu	kr_oil	kr_gas	kr_aq
0.500	0.0000	1.0000	0.0000	0.0000	0.0000	0.4426
1.500	0.0000	1.0000	0.0000	0.0000	0.0000	0.4428
2.500	0.0000	1.0000	0.0000	0.0000	0.0000	0.4491
3.500	0.1404	0.8596	0.0000	0.0000	0.5185	0.0000
4.500	0.6278	0.3722	0.0000	0.2741	0.0151	0.0000
5.500	0.9747	0.0253	0.0000	0.6489	0.0000	0.0000
6.500	0.0000	0.4493	0.5507	0.0000	0.0427	0.1372
7.500	0.0000	0.3654	0.6345	0.0000	0.0098	0.3120
8.500	0.0000	0.3621	0.6379	0.0000	0.0105	0.3257
9.500	0.0000	0.3550	0.6450	0.0000	0.0098	0.3502
10.580	0.0000	0.3515	0.6485	0.0000	0.0090	0.3628
11.835	0.0000	0.4453	0.5546	0.0000	0.0485	0.1245
13.291	0.0000	0.6141	0.3859	0.0000	0.2400	0.0050
14.982	0.0000	0.6146	0.3854	0.0000	0.2409	0.0049
16.945	0.0000	0.6145	0.3854	0.0000	0.2409	0.0049
19.223	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049

21.869	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
24.940	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
28.506	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
32.646	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
37.452	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
43.031	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
49.509	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
57.029	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
65.759	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
75.895	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
87.663	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
101.324	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
117.184	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
135.597	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
156.974	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
181.792	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
210.604	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
244.053	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
282.887	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
327.971	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
380.312	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
441.077	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
511.623	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
593.524	0.0000	0.6145	0.3855	0.0000	0.2408	0.0049
688.607	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
798.995	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
927.150	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
1075.9	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
1248.7	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
1449.2	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
1682.0	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
1952.3	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
2266.1	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049
2630.4	0.0000	0.6145	0.3854	0.0000	0.2408	0.0049

Overall concentrations:

X (ft)	H2O	N2	C1	C2	C3	C4-6	C7-16	DME
0.500	1.00E-10	0.999998	1.00E-10	1.00E-10	1.00E-10	6.33E-09	1.00E-10	2.25E-06
1.500	9.71E-08	0.99985	4.95E-08	1.24E-08	5.84E-09	6.33E-09	1.05E-08	1.50E-04
2.500	3.10E-05	0.984497	1.84E-05	4.55E-06	2.12E-06	2.26E-06	3.10E-06	1.54E-02
3.500	7.05E-03	0.568946	2.77E-03	6.92E-04	3.21E-04	3.53E-04	7.37E-04	0.419128

4.500	0.028938	0.332742	2.17E-02	5.22E-03	0.002367	2.38E-03	0.003044	0.603583
5.500	0.1103	0.10492	6.03E-02	1.37E-02	5.55E-03	5.23E-03	6.12E-03	0.693927
6.500	0.196076	3.51E-02	0.101528	2.24E-02	8.72E-03	8.01E-03	8.16E-03	0.620054
7.500	0.5626	2.23E-03	8.74E-02	1.90E-02	7.10E-03	6.07E-03	3.98E-03	0.311676
8.500	0.8545	4.22E-04	7.52E-02	1.56E-02	5.64E-03	4.47E-03	1.39E-03	4.28E-02
9.500	0.896546	4.04E-04	7.61E-02	1.56E-02	5.65E-03	4.41E-03	9.58E-04	2.96E-04
10.580	0.898226	4.03E-04	7.51E-02	1.54E-02	5.58E-03	4.36E-03	9.42E-04	7.79E-07
11.835	0.856299	5.69E-04	0.105998	2.18E-02	7.88E-03	6.15E-03	1.33E-03	8.41E-07
13.291	0.750552	9.88E-04	0.184	3.78E-02	1.37E-02	1.07E-02	2.31E-03	9.99E-07
14.982	0.750165	9.89E-04	0.184285	3.79E-02	1.37E-02	1.07E-02	2.31E-03	9.99E-07
16.945	0.750167	9.89E-04	0.184284	3.78E-02	1.37E-02	1.07E-02	2.31E-03	9.99E-07
19.223	0.750168	9.89E-04	0.184283	0.03785	1.37E-02	1.07E-02	2.31E-03	9.99E-07
21.869	0.75017	9.89E-04	0.184282	3.78E-02	0.013701	1.07E-02	2.31E-03	9.99E-07
24.940	0.75017	9.89E-04	0.184281	3.78E-02	1.37E-02	0.010696	2.31E-03	9.99E-07
28.506	0.750171	9.89E-04	0.184281	3.78E-02	1.37E-02	1.07E-02	2.31E-03	9.99E-07
32.646	0.750172	9.89E-04	0.18428	0.037849	1.37E-02	1.07E-02	2.31E-03	9.99E-07
37.452	0.750172	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
43.031	0.750172	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
49.509	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
57.029	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
65.759	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	0.010696	2.31E-03	1.00E-06
75.895	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	0.010696	0.002312	1.00E-06
87.663	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	0.010696	0.002312	1.00E-06
101.324	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	0.010696	0.002312	1.00E-06
117.184	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	0.010696	0.002312	1.00E-06
135.597	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	0.010696	2.31E-03	1.00E-06
156.974	0.750173	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
181.792	0.750172	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
210.604	0.750172	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
244.053	0.750172	9.89E-04	0.18428	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
282.887	0.750171	9.89E-04	0.184281	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
327.971	0.750171	9.89E-04	0.184281	3.78E-02	1.37E-02	0.010696	2.31E-03	1.00E-06
380.312	0.75017	9.89E-04	0.184282	3.78E-02	0.013701	1.07E-02	2.31E-03	1.00E-06
441.077	0.750168	9.89E-04	0.184283	0.03785	1.37E-02	1.07E-02	2.31E-03	1.00E-06
511.623	0.750167	9.89E-04	0.184284	3.78E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
593.524	0.750164	9.89E-04	0.184286	0.03785	1.37E-02	1.07E-02	2.31E-03	1.00E-06
688.607	0.750161	9.89E-04	0.184288	3.79E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
798.995	0.750158	9.89E-04	0.184291	3.79E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
927.150	0.750152	9.89E-04	0.184295	3.79E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
1075.9	0.750146	9.89E-04	0.184299	0.037853	0.013702	1.07E-02	2.31E-03	1.00E-06
1248.7	0.750138	9.89E-04	0.184305	3.79E-02	1.37E-02	0.010697	2.31E-03	1.00E-06
1449.2	0.750128	9.89E-04	0.184313	3.79E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
1682.0	0.750117	9.90E-04	0.184321	3.79E-02	0.013704	0.010698	2.31E-03	1.00E-06

1952.3	0.750105	9.90E-04	0.18433	3.79E-02	1.37E-02	0.010699	2.31E-03	1.00E-06
2266.1	0.750095	9.90E-04	0.184337	3.79E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06
2630.4	0.750088	9.90E-04	0.184342	3.79E-02	1.37E-02	1.07E-02	2.31E-03	1.00E-06

### **Appendix B: UTCOMP Input File Sample**

```
CC CO2-NGL SOLVENT EOR (12 components, 4-phase) *
CC Created by Sajjad S. Neshat UTCOMP 4.0 *
CC Date : 02-17-2016 /2D Heterogeneous *
CC *
CC HYDROCARBON DATA AND FLASH CALCULATION OPTIONS *
CC*
CC *
CC..+...1...+...2...+...3...+...4...+...5...+...6...+...7.
CC CASE NAME WITH FORMAT (17A4, A2) OF TOTAL 70 COLUMNS.
*----HEADER
CC
CC NUMBER OF COMPONENTS.
*----NC
   12
CC COMPONENT NAMES WITH FORMAT (1X, A8), NC CARDS.
CC...+..12
*----NAME
  CO<sub>2</sub>
  C1
  C2
  C3
  nC4
  nC5
  C6
  C79
  C1013
  C1419
  C2035
  C36+
CC BLACK OIL OPTION, SALINITY, AQUIFER OPTION
CC (0:OFF,1:ON) PPM (0:OFF,1:ON)
*----IBOST
          SLNTY IAQUIF
    0
        0.
             0
CC CRITICAL PRESS. (PSI), TEMP. (R) AND VOL. (CU FT/LB-MOLE), update PARACh.chengwu
CC MOLECULAR WT. (LB/LB-MOLE), ACENTRIC FACTOR, PARACHOR. NC CARDS. ** 19.806<=22.806
*----PC
          TC
                VC
                      WT
                            OM
                                  PARACH
                                          VSP
   1071.60 547.57 1.166
                      44.01
                           0.2250 125.7429 -0.08781
   667.80 343.04 1.602
                     16.04
                           0.0130 45.8286
                                         -0.11800
   707.80 549.76 2.451
                      30.07 0.0986 85.9143
                                         -0.10700
   616.30 665.68 3.300 44.10 0.1524 126.0000 -0.08480
                     58.12
   550.70 765.32 4.088
                           0.2010 166.0571 -0.0686
   488.60 845.37 4.946
                     72.15
                           0.2539 206.1429 -0.041
   483.77 923.00 5.294 84.00 0.2583 240.0000 0.0212
   415.41 1040.29 8.553 145.16 0.3165 311.8857
                                          0.10910
   255.39 1199.64 13.110 223.26 0.4255 437.8857
                                           0.32570
         1346.56 23.070 353.51
   203.91
                             0.5768 638.6000
                                           0.28470
   158.03 1532.74 33.253 554.55 0.7659 1070.1429 0.30439
   94.80
        1967.34 83.571 1052.00 1.1313 2062.8571 0.36470
CC EOS parameters (Ac and Bc)
```

CC NC CARDS. \*----PARAA PARAB 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 0.457236 0.0778 CC CC BINARY INTERACTION COEFFICIENTS, CIJ. NC CARDS. \*----DELTA 0.00000 0.07162 0.00000 0.09399 0.00519 0.00000 0.09759 0.01677 0.00394 0.00000  $0.09397\ 0.03675\ 0.01226\ 0.00000\ 0.00000$ 0.09034 0.04421 0.02316 0.00001 0.00000 0.00000 0.07454 0.00000 0.03071 0.01065 0.00026 0.00003 0.00000 0.09191 0.00001 0.05030 0.02209 0.00083 0.00045 0.00001 0.00000 0.09863 0.00001 0.00497 0.00259 0.00205 0.00122 0.00001 0.00001 0.00000 0.11636 0.16940 0.04511 0.02952 0.01012 0.01001 0.00001 0.00001 0.00000 0.00000 0.11636 0.17835 0.06547 0.05574 0.02093 0.01921 0.00002 0.00002 0.00000 0.00000 0.00000  $0.16348\ 0.18222\ 0.13363\ 0.12456\ 0.05379\ 0.04953\ 0.00004\ 0.00002\ 0.00001\ 0.00001\ 0.00002\ 0.000$ CC CC BINARY INTERACTION COEFFICIENTS, DIJ. NC CARDS. \*----DELTA 0.000 0.000 0.000  $0.000 \quad 0.000 \quad 0.000$ 0.000 0.000 0.000 0.0000.000 0.000 0.000 0.000 0.000  $0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000$  $0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000$  $0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000 \quad 0.000$  $0.000 \quad 0.000 \quad 0.000$  $0.000 \quad 0.000 \quad 0.00$  $0.000 \quad 0.000 \quad 0.00$ 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 CC CC MAXIMUM NUMBER OF PHASES (3 OR 4) \*-----NP IVISC ISINGL ISOLU 4 1 0 0 CC IEOS: 1, IPEM: 0 OR 1 CC ISTAM: -1, 0 OR 1, IEST: 0 OR 1 KI: 0, 1 OR 2 \*---IEOS IPEM ISTAM IEST IVSP KI INI2 1 0 0 1 0 0 0 CC CC ITERATION TOLERANCES FOR PERSCHKE'S FLASH ROUTINES. \*----TOLFLA TOLFLM TOLPD TOLSAM TOLSAS TOLSUM 1.E-07 1.E-09 1.E-10 1.E-09 1.E-09 1.E-07

CC CC MAXIMUM NUMBER OF ITERATIONS FOR PERSCHKE'S FLASH ROUTINES. \*----MAXFLA MAXFLM MAXPD MAXSAM MAXSAS 1000 1000 1000 1000 1000 CC CC VECTOR FLASH OPTION \*----IVECFL TOLVFL MAXVFL 0 1.E-10 30 CC CC SWITCHING PARAMETERS FOR PERSCHKE'S FLASH ROUTINES. \*----SWIPCC SWIPSA .001 .01 CC CC PHASE IDENTIFICATION PARAMETERS FOR PERSCHKE'S FLASH ROUTINES. \*-----IOIL ITRK DMSLIM 1 4 25. С CC IFLAGT (0: OFF, 1: ON) \*-----IFLAGT IASPR 0 0 С CC GFE REFENCE VALUES (1/2/3/4) \*-----G1R G2R G3R -9.55 5.4 6.9 С CC THREE PHASE RESIDUAL SATURATION COEFFICIENTS \*-----b1 b2 b3 b4 0 1 0.5 0 CC CC \* CC OUTPUT OPTIONS \* CC\* CC CC CC HISTORY PRINTING PARAMETER FOR <<HISTORY.CPR>>. \*---NHSSKIP NSTSKIP IPV 50 50 0 CC CC REFERENCE CONCENTRATION, CONCO, USED FOR EFFLUENT CONCENTRATION of each comps. \*----CONC0 CC CC NUMBER OF PRINTS FOR <<TABLE.CPR>>. \*-----NPR (100 max) 13 CC CC TIME(DAYS) AND FLAGS (0 OR 1) FOR << TABLE.CPR>>. NPR CARDS. -----TPR MPRP MPRSAT MPROMFR MPRPMFR MPRPRO MPRATES 0.01 1 1 1 1 1 1 10 1 1 1 1 1 1 20 1 1 1 1 1 1 30 1 1 1 1 1 1 40 1 1 1 1 1 1 50 1 1 1 1 1 1

60 1 1 1 1 1 1 70 1 1 1 1 1 1 80 1 1 1 1 1 1 90 1 1 1 1 1 1 100 1 1 1 1 1 1 110 1 1 1 1 1 1 125 1 1 1 1 1 1 CC CC NUMBER OF PRINTS FOR << PROFILE.CPR>>. \*-----NPF 163 CC CC TIME(DAYS) AND FLAGS ( 0 OR 1 ) FOR << PROFILE.CPR>>. NPF CARDS. \*-----TPF MPFSAT MPFOMFR MPFPMFR MPFPROP 1 0.01 1 1 1 10 1 1 1 1 20 1 1 1 1 30 1 1 1 1 40 1 1 1 1 50 1 1 1 1 60 1 1 1 1 70 1 1 1 1 80 1 1 1 1 1 90 1 1 1 100 1 1 1 1 110 1 1 1 1 125 1 1 1 1 CC CC NUMBER OF PRINTS FOR <<CONTOUR.CPR>>. \*-----NCT 1 CC CC TIME(DAYS) AND FLAGS ( 0 OR 1 ) FOR <<CONTOUR.CPR>>. NCT CARDS. \*-----TCT(DAY) MCTP MCTSAT MCTOMFR MCTPMFR MCTPRO 100.0 1 1 1 1 1 1 CC CC \* CC RESERVOIR AND WELL DATA \* CC \* CC CC A FLAG FOR RESERVOIR GEOMETRY: CC 2-D: 11(Y), 12(X), 13(Z), 2-D: 21(XY), 22(YZ), 23(XZ), 3-D: 31 \*-----IGEOM INUG 23 0 CC CC NUMBER OF GRID BLOCKS IN X, Y, AND Z. \*-----NX NY NZ 25 1 10 CC CC NUMBER OF WELLS \*----NW 2 1 CC

```
CC WELLBORE RATIUS (FT). NW NUMBERS.
*-----RW: (NW)
    0.33 0.33
CC
CC WELL LOCATIONS. NW CARDS.
*-----LXW LYW IDIR LZWF LZWL
   1 1 3 1 11
   25 1 3 1 11
CC
CC A FLAG (0 OR 1) FOR GRID BLOCK SIZE IN X-DIRECTION.
*-----MDX
    0
CC
CC CONSTANT GRID BLOCK SIZE IN X-DIRECTION (FT).
*-----DX
    40.0
CC
CC A FLAG (0 OR 1) FOR GRID BLOCK SIZE IN Y-DIRECTION.
*-----MDY
    0
CC
CC CONSTANT GRID BLOCK SIZE IN Y-DIRECTION (FT).
*-----DY
   50.0
CC
CC A FLAG (0 OR 1) FOR GRID BLOCK SIZE IN Z-DIRECTION.
*-----MDZ
    0
CC
CC CONSTANT GRID BLOCK SIZE IN Z-DIRECTION (FT).
*-----DZ
    5.0
CC
CC A FLAG (0 OR 1) FOR FORMATION DEPTH.
*-----MD
    0
CC
CC DEPTH (FT) OF THE MOST UPPER LAYER.
*----D
    4100.0
CC
CC A FLAG (0 OR 1) FOR FORMATION POROSITY.
*-----MPOR
    1
CC
CC HOMOGENEOUS POROSITY (FRACTION) AT PF.
*----PORSTD
.263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268
.263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268
.263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268
.263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268
                        .280 .291 .289 .274 .298 .268
.263 .277 .313 .270 .252
.263 .277 .313
              .270 .252
                        .280
                             .291
                                  .289 .274
                                           .298
                                                .268
.263 .277 .313
              .270 .252
                        .280
                            .291
                                  .289 .274
                                           .298
                                                .268
.263 .277 .313 .270 .252 .280 .291 .289 .274
                                           .298 .268
.263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268
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.263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268 .277 .270 .252 .280 .291 .289 .274 .298 .263 .313 .268 .291 .263 .277 .313 .270 .252 .280 .289 .274 .298 .268 .280 .291 .263 .277 .313 .270 .252 .289 .274 .298 .268 .277 .252 .280 .291 .274 .298 .263 .313 .270 .289 .268 .277 .270 .252 .280 .291 .289 .274 .298 .268 .263 .313 .270 .252 .280 .291 .289 .274 .298 .263 .277 .313 .268 .291 .263 .277 .313 .270 .252 .280 .289 .274 .298 .268 .263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268 .313 .270 .252 .280 .291 .289 .274 .298 .268 .263 .277 .291 .263 .277 .313 .270 .252 .280 .289 .274 .298 .268 .298 .263 .277 .313 .270 .252 .280 .291 .289 .274 .268 .252 .280 .277 .313 .270 .291 .289 .274 .298 .263 .268 .263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268 .263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268 .263 .277 .313 .270 .252 .280 .291 .289 .274 .298 .268 CC CC CC A FLAG (0 OR 1) FOR PERMEABILITY IN X-DIRECTION. \*----MPERMX 1 CC CC HOMOGENEOUS PERMEABILITY (MD) IN X-DIRECTION. \*----PERMX 171.0 171.0 171.0 171.0 171.0 171.0 171.0 171.0 171.0 3.957 12.92 415.6 1017. 15.77 149.5 331.2 260.3 132.0 1.962 20.32 361.8 1738. 20.76 84.97 171.6 428.1 133.6 3.660 22.42 395.8 1923. 38.91 121.9 123.8 269.6 174.3 2.632 18.04 805.0 51.82 105.4 57.16 149.2 86.60 511.4 5.084 16.02 369.8 27.24 83.99 62.52 182.2 683.4 84.26 6.663 19.26 214.5 446.5 31.64 80.37 79.86 169.3 31.90 13.08 42.79 198.9 123.0 211.6 22.33 58.63 100.1 44.66 44.18 29.49 246.5 138.1 51.82 75.06 51.42 153.1 17.51 28.35 22.35 442.2 220.0 26.27 80.46 68.48 153.8 21.46 25.72 34.77 371.6 133.3 32.87 64.84 89.18 155.5 15.71 37.71 21.72 19.39 122.8 75.94 161.7 121.4 52.84 15.58 22.19 47.59 28.78 158.1 125.0 118.7 131.5 63.60 7.871 27.90 95.35 99.42 57.50 43.78 287.4 107.1 7.475 110.1 62.97 65.19 173.7 58.62 32.80 115.1 80.23 55.18 9.298 62.26 57.52 145.7 35.52 78.82 90.31 42.63 57.28 13.61 59.03 53.51 108.0 48.95 155.8 119.4 59.27 86.32 8.379 65.38 46.55 114.6 20.95 170.4 93.72 104.2 132.4 14.96 72.17 23.26 125.6 45.13 231.7 78.82 103.4 239.0 10.94 38.49 38.21 194.0 50.58 204.4 123.5 262.1 74.37 5.159 23.28 76.52 289.2 34.92 126.6 110.6 69.94 274.6 5.870 17.17 61.94 228.3 46.78 186.8 145.5 230.2 9.840 85.18 38.84 84.40 153.8 57.59 460.4 184.1 119.2 224.5 4.958 37.69 82.57 89.00 70.09 493.9 198.5 95.68 111.3 3.656 171.0 171.0 171.0 171.0 171.0 171.0 171.0 171.0 171.0

171.0

375.4

696.7

499.2

542.1

647.1

904.3

794.7

539.0

264.6

168.9

85.95

58.41

34.83

31.99

22.71

26.50

18.30

24.87

28.27

31.26

79.62

32.37

36.66

171.0

171.0

341.7

325.7

453.7

264.7

237.0

730.9

590.3

616.6

561.2

543.3

279.2

244.1

198.8

178.1

116.3

115.0

141.7

176.8

138.7

169.9

164.1

104.4

92.65

171.0

CC

CC A FLAG (0 OR 1) FOR PERMEABILITY IN Y-DIRECTION.

\*----MPERMY 1

CC

CC HOMOGENEOUS PERMEABILITY (MD) IN Y-DIRECTION.

CC

*PER	MY									
171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0
3.957	12.92	415.6	1017.	15.77	149.5	331.2	260.3	132.0	375.4	341.7
1.962	20.32	361.8	1738.	20.76	84.97	171.6	428.1	133.6	696.7	325.7
3.660	22.42	395.8	1923.	38.91	121.9	123.8	269.6	174.3	499.2	453.7
2.632	18.04	511.4	805.0	51.82	105.4	57.16	149.2	86.60	542.1	264.7
5.084	16.02	369.8	683.4	27.24	83.99	62.52	182.2	84.26	647.1	237.0
6.663	19.26	214.5	446.5	31.64	80.37	79.86	169.3	31.90	904.3	730.9
13.08	42.79	123.0	211.6	22.33	58.63	100.1	198.9	44.66	794.7	590.3
44.18	29.49	246.5	138.1	51.82	75.06	51.42	153.1	17.51	539.0	616.6
28.35	22.35	442.2	220.0	26.27	80.46	68.48	153.8	21.46	264.6	561.2
25.72	34.77	371.6	133.3	32.87	64.84	89.18	155.5	15.71	168.9	543.3
37.71	21.72	161.7	121.4	19.39	122.8	52.84	75.94	15.58	85.95	279.2
47.59	28.78	158.1	125.0	22.19	118.7	131.5	63.60	7.871	58.41	244.1
57.50	43.78	287.4	110.1	27.90	95.35	107.1	99.42	7.475	34.83	198.8
62.97	65.19	173.7	58.62	32.80	115.1	80.23	55.18	9.298	31.99	178.1
62.26	57.52	145.7	35.52	78.82	90.31	42.63	57.28	13.61	22.71	116.3
59.03	53.51	108.0	48.95	155.8	119.4	59.27	86.32	8.379	26.50	115.0
65.38	46.55	114.6	20.95	170.4	93.72	104.2	132.4	14.96	18.30	141.7
72.17	23.26	125.6	45.13	231.7	78.82	103.4	239.0	10.94	24.87	176.8
38.49	38.21	194.0	50.58	204.4	123.5	74.37	262.1	5.159	28.27	138.7
23.28	76.52	289.2	34.92	126.6	110.6	69.94	274.6	5.870	31.26	169.9
17.17	61.94	228.3	46.78	186.8	145.5	85.18	230.2	9.840	79.62	164.1
38.84	84.40	153.8	57.59	460.4	184.1	119.2	224.5	4.958	32.37	104.4
37.69	82.57	89.00	70.09	493.9	198.5	95.68	111.3	3.656	36.66	92.65
171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0	171.0

CC

CC FLAG (0 OR 1) FOR PERMEABILITY IN Z-DIRECTION.

\*----MPERMZ

1

1										
CC										
CC HOM	OGENEOU	US PERMI	EABILITY	(MD) IN	Z-DIRECT	TION.				
*PER	MZ									
0.2096	1.884	40.39	65.16	3.911	17.59	55.58	26.55	20.19	71.36	29.13
0.3957	1.292	41.56	101.7	1.577	14.95	33.12	26.03	13.20	37.54	34.17
0.1962	2.032	36.18	173.8	2.076	8.497	17.16	42.81	13.36	69.67	32.57
0.3660	2.242	39.58	192.3	3.891	12.19	12.38	26.96	17.43	49.92	45.37
0.2632	1.804	51.14	80.50	5.182	10.54	5.716	14.92	8.660	54.21	26.47
0.5084	1.602	36.98	68.34	2.724	8.399	6.252	18.22	8.426	64.71	23.70
0.6663	1.926	21.45	44.65	3.164	8.037	7.986	16.93	3.190	90.43	73.09
1.308	4.279	12.30	21.16	2.233	5.863	10.01	19.89	4.466	79.47	59.03
4.418	2.949	24.65	13.81	5.182	7.506	5.142	15.31	1.751	53.90	61.66
2.835	2.235	44.22	22.00	2.627	8.046	6.848	15.38	2.146	26.46	56.12
2.572	3.477	37.16	13.33	3.287	6.484	8.918	15.55	1.571	16.89	54.33
3.771	2.172	16.17	12.14	1.939	12.28	5.284	7.594	1.558	8.595	27.92
4.759	2.878	15.81	12.50	2.219	11.87	13.15	6.360	0.7871	5.841	24.41
5.750	4.378	28.74	11.01	2.790	9.535	10.71	9.942	0.7475	3.483	19.88
6.297	6.519	17.37	5.862	3.280	11.51	8.023	5.518	0.9298	3.199	17.81
6.226	5.752	14.57	3.552	7.882	9.031	4.263	5.728	1.361	2.271	11.63
5.903	5.351	10.80	4.895	15.58	11.94	5.927	8.632	0.8379	2.650	11.50
6.538	4.655	11.46	2.095	17.04	9.372	10.42	13.24	1.496	1.830	14.17
7.217	2.326	12.56	4.513	23.17	7.882	10.34	23.90	1.094	2.487	17.68
3.849	3.821	19.40	5.058	20.44	12.35	7.437	26.21	0.5159	2.827	13.87
2.328	7.652	28.92	3.492	12.66	11.06	6.994	27.46	0.5870	3.126	16.99
1.717	6.194	22.83	4.678	18.68	14.55	8.518	23.02	0.9840	7.962	16.41
3.884	8.440	15.38	5.759	46.04	18.41	11.92	22.45	0.4958	3.237	10.44

3.769 8.257 8.900 7.009 49.39 19.85 9.568 0.3656 3.666 9.265 11.13 44.00 10.56 10.75 10.69 8.733 23.44 7.370 6.494 0.5528 4.097 12.65 CC CC FORMATION COMPRESSIBILITY (1/PSI) AND REFERENCE PRESSURE (PSI). \*----CF PF 50.0e-6 14.65 CC H2O COMPRESSIBILITY (1/PSI), REFERENCE PRESSURE (PSI) AND CC MOLAR DENSITY (LB-MOLE/CU FT). \*-----CW PW DENMWS 3.3e-6 14.65 3.467 CC CC WATER MOLECULAR WT. (LBM/LBM-MOLE) AND VISCOSITY (CP). \*-----WTW VISCW 18. 0.79 CC CC FORMATION TEMPERATURE (F). \*----TEMPF 86.0 CC CC STANDARD TEMPERATURE (F) AND STANDARD PRESSURE (PSI). \*----TFSTD PSTD 60. 14.696 CC CC A FLAG (1, 2, 3 OR 4) FOR NUMERICAL DISPERSION CONTROL. \*----IUPSTW 4 CC CC ITC (0: NO 2ND ORDER TIME, 1: 2ND ORDER TIME ON) \*----ITC 0 CC RESTART OPTIONS. CC ISTART (1 OR 2), ISTORE (0 OR 1). \*----ISTART ISTORE 1 1 CC CC A FLAG (0 OR 1) FOR AUTOMATIC TIME-STEP SELECTION (=1). \*-----MDT 1 CC CC A FLAG (0 OR 1) FOR PHYSICAL DISPERSION CALCULATION. \*----MDISP 0 CC FLAGS FOR RELATIVE PERMEABILITY MODEL AND CAPILLARY PRESSURE. CC IPERM (1 OR 2), ICPRES (0 OR 1). \*-----IPERM ICPRES ICAP IRPERM IRSFT 4 0 2 0 0 CC CAPILLARY PRESSURE PARAMETERS AND CC WATER/OIL INTERFACIAL TENSION (DYNES/CM). \*-----EPC CPC RIFTWO RIFTWG RIFTWL 2. 2.0 20. 24. 30. CC CC HIGH IFT RESIDUAL SATURATIONS. \*-----S1RW S2RW1 S2RW2 S3RW S4RW1 S4RW2 .05 .25 .3 .3 .2 .2 CC CC LOW IFT RESIDUAL SATURATIONS.

\*-----S1RC S2RC1 S2RC2 S3RC S4RC1 S4RC2  $0.0 \ 0.0 \ 0.0 \ 0.0 \ 0.0 \ 0.0$  $\mathbf{C}\mathbf{C}$ CC HIGH IFT END POINT RELATIVE PERMEABILITY. \*-----P1RW P2RW P3RW P4RW .9 0.7 .2 .5 CC CC LOW IFT END POINT RELATIVE PERMEABILITY. \*-----P1RC P2RC P3RC P4RC 1. 1. 1. 1. CC CC HIGH IFT EXPONENT OF RELATIVE PERMEABILITY. \*-----E1W E2W1 E2W2 E3W E4W1 E4W2 1.5 2 2 3 2 2 CC CC LOW IFT EXPONENT OF RELATIVE PERMEABILITY. \*-----E1C E2C1 E2C2 E3C E4C1 E4C2 1. 1. 1. 1. 1. 1. CC CC WATER AND L1 PHASE CAPILLARY DESATURATION PARAMETERS. \*-----T11 T12 T211 T221 T212 T222 1000 1000 20000 20000 20000 20000 CC CC GAS AND L2 PHASE CAPILLARY DESATURATION PARAMETERS. \*-----T31 T32 T411 T421 T412 T422 50000 50000 30000 30000 30000 30000 CC CC A FLAG FOR PRESSURE EQUATION SOLVER (1, 2, 3, 4 OR 5). \*----IPRESS IPREC METHSL OMEGA 4 2 1 1.0 CC CC ITERATIVE PRESSURE SOLVER PARAMETERS. \*-----ITMAX LEVLIT IDGTS NS1 NS2 ZETA 1000 1 1 5 1000000 1.E-07 CC CC INITIAL TIME (DAYS). \*-----T 0 CC CC A FLAG (0 OR 1) FOR INITIAL PRESSURE. \*-----MP 0 CC CC CONSTANT INITIAL PRESSURE (PSIA). \*-----P 1750.0 CC CC A FLAG (0 OR 1) FOR INITIAL WATER SATURATION. \*----MSAT 0 CC CC CONSTANT INITIAL WATER SATURATION (FRACTION). \*-----SAT 0.4 CC CC A FLAG (0 OR 1) FOR INITIAL OVERALL COMPOSITION.

```
*----MOMFR
  0
CC
CC CONSTANT INITIAL COMPOSITION (MOLE FRACTION).
*----OMFR
 .000436 .272149 .004128 .010484 .021230 .020020
 .022566 .098746 .100533 .145138 .164159 .140411
CC
CC *
CC RECURRENT DATA *
CC*
CC
CC MAXIMUM TIME (DAYS), TIME STEP (DAYS) AND WELL DATA.
*-----TM DT NWELLS GORLIM WORLIM ------
   28.5 .0001 2 -1.0 -1.0
CC
CC parameters for time step selections.
*----DTMAX DTMIN DSLIM DPLIM DVLIM DMFACT
  .25 .0001 0.05
                0.005 0.01 0.05
CC
CC WELL NO. AND WELL TYPE.
*-----LW IQTYPE
   1
       2
CC
CC CONSTANT BHP INJECTION WELL
*----QTMLC FWMLC NCOMP
 1800.0 0 6
CC
CC INJECTANT COMPOSITION
*-----KC Z1
  1
      0.8150
      0.0043
   4
   5
      0.0798
   6
      0.0522
   7
      0.0267
   8
      0.0220
CC
CC WELL NO. AND WELL TYPE.
*-----LW IQTYPE
   2 -2
CC CONSTANT BHP PRODUCER
CC
*---- PBHC ANG
    800 0
CC
CC MAXIMUM TIME (DAYS), TIME STEP (DAYS) AND WELL DATA.
*-----TM DT NWELLS GORLIM WORLIM -----
   78.0 1e-3 2 -1.0e+20 -1.0e+10
CC
CC parameters for time step selections.
*-----DTMAX DTMIN DSLIM DPLIM DVLIM DMFACT
                0.005 0.01 0.05
  .1 .00001 0.05
CC
```

CC WELL NO. AND WELL TYPE. \*-----LW IQTYPE 1 2 CC CC CONSTANT BHP INJECTION WELL \*----QTMLC FWMLC NCOMP 1800.0 0 6 CC CC INJECTANT COMPOSITION \*-----KC Z1 1 0.8150 0.0043 4 5 0.0798 6 0.0522 7 0.0267 8 0.0220 CC CC WELL NO. AND WELL TYPE. \*-----LW IQTYPE 2 -2 CC CONSTANT BHP PRODUCER CC \*---- PBHC ANG 800 0 CC CC MAXIMUM TIME (DAYS), TIME STEP (DAYS) AND WELL DATA. \*-----TM DT NWELLS GORLIM WORLIM ------125.0 1e-4 2 -1.0e+20 -1.0e+10 CC CC parameters for time step selections. \*-----DTMAX DTMIN DSLIM DPLIM DVLIM DMFACT .05 .00001 0.05 0.005 0.01 0.05 CC CC WELL NO. AND WELL TYPE. \*-----LW IQTYPE 1 2 CC CC CONSTANT BHP INJECTION WELL \*----OTMLC FWMLC NCOMP 1800.0 0 6 CC CC INJECTANT COMPOSITION \*-----KC Z1 1 0.8150 4 0.0043 5 0.0798 6 0.0522 7 0.0267 8 0.0220 CC CC WELL NO. AND WELL TYPE. \*-----LW IQTYPE 2 -2 CC CONSTANT BHP PRODUCER CC \*---- PBHC ANG

800 0 CC CC End of simulation \*-----TM DT NWELLS GORLIM WORLIM -------1. -1. -1 -1.E10 -1.E10

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