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Master Thesis

“Sensitivity Analysis of Interwell Partitioning Tracer Tests”

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Abstract

The use of Partitioning Interwell Tracer Test is examined in the current thesis through the scope of black oil and chemical simulators (ECLIPSE and UTCHEM). Tracer tests have been thoroughly applied over the past decades as a means of reservoir characterisation. Partitioning Interwell Tracer Test is considered as a useful method for estimating oil volume and oil saturation, particularly before the application of Enhanced Oil Recovery methods, where the remaining oil saturation is close at its residual value. The accuracy of such predictions is investigated through the usage of ECLIPSE and UTCHEM simulators. Also, a sensitivity analysis to oil saturation distribution is conducted with regards residual oil saturation estimations.

As chemical compounds, it is important to determine whether tracers' transportation in the porous medium is sufficiently described through the equations that are provided in the aforementioned simulators. The latter are not meant to fully encapsulate all the probable mechanisms and reactions that may occur as tracers are injected into the reservoir and flow across the rock material.

Numerical methods are also examined in the case of reservoirs that exhibit a non-residual saturation value. Furthermore, the use of partitioning tracers is investigated in heterogeneous reservoirs as well as in naturally fractured reservoirs as a qualitative means that may lead to useful information about flow patterns that cannot be easily deduced solely from production data themselves.

1. Thesis Outline

In the second chapter the literature review of tracer methods is illustrated, as well as the fundamentals of reservoir simulation.

In the third chapter the results of simulation runs conducted for a 1D grid are presented (oil exhibits a residual saturation value). The same study case was examined through ECLIPSE and UTCHEM and the resultant non-partitioning tracer break-out curves were compared with the analytical solution.

Sensitivity analysis results from ECLIPSE and UTCHEM, with regards to oil saturation distribution are illustrated in the fourth chapter. Oil exhibits an irreducible saturation value in each distinct grid block regardless of the saturation distribution pattern.

Results from study cases concerning reservoir cases that exhibit a non-residual oil saturation can be found in the fifth chapter, for various initial oil saturations. A high value of the latter indicates reservoir cases just after depletion whereas low values of remaining oil saturation point towards a mature field after water injection. Heterogeneous reservoir cases were examined, comprising a multilayer reservoir and a thief-zone one.

In the sixth chapter, results regarding naturally fractured reservoir are presented. Dual porosity, dual permeability and discrete fracture models were performed for this study case.

The oil/water saturation distributions for the several wettability systems may be found in *Appendix A*. The various codes that were used in the aforementioned study cases for both ECLIPSE and UTCHEM can be found in the *Appendix B* and *Appendix C*, respectively.

2. Theoretical Setting

2.1. Tracers

Apart from production data themselves, information about a reservoir and its properties can be obtained through pressure and tracer testing.

With over sixty years of field application the latter is a common technique in reservoir engineering. Numerous chemicals have been produced and several techniques have been employed worldwide.

In a rough description, tracer testing is the injection of chemical compounds into the subsurface in order to estimate its flow and storage properties (*Shook et al., 2004*). Tracer testing is broadly implemented before IOR and particularly EOR methods (i.e. for the determination of probable high permeable zones that would deteriorate water or gas injection into the reservoir). Pressure tests have a similar application; that is the connectivity between two wells. The latter however, mainly utilise average properties (averaged by the bulk volume) between the wells, which may lead to low resolution results. On the other hand, tracers may provide more rigorous information in terms of the degree of heterogeneity and the swept pore volume (*Yahyaoui, 2017*).

In terms of their properties tracers can be classified as radioactive (compounds that contain radioactive isotopes) or chemicals. The latter can be further divided into three categories: dyes (i.e rhodamine and fluorescein), ionic (anions of water soluble salts) and organic.

A much more valuable characterization pertains to the phase that tracers exist. According to that, tracers are either:

- **Conservative:** Often referred to as passive or non-partitioning. Ideally, a conservative tracer follows blindly the phase that is supposed to live in. Hence, a passive water tracer exhibits the same velocity with water, does not interact with other phases and has low adsorption to the rock. The most common passive water tracer is tritiated water (HTO) where hydrogen is replaced by tritium isotope (*Zemel and Bernard, 1995*).

- **Partitioning:** Also referred to as active ones. These are additionally soluble to a second phase as well. For instance, an oil-water tracer partitions between the two phases which leads to a retardation of the tracer front. The longer it partitions in the second phase the greater the retardation. The latter is quantified through the Partition Coefficient (K_d). Originally described by Martin and Synge (1941) the transportation of substances that partition between different phases has been the epicentre of many studies throughout the years (*Bouchard et al., 1989, Jin* *et al., 1995*). Multi-partition tracers have been produced that partition in more than two phases (for instance between water, oil and gas).

Those tracers can be used in two major types of testing:

- **Single Well Chemical Test (SWCT)**: Chiefly conducted for the determination of residual oil saturation. Tracers (normally one passive and one active) are injected into the well and after a small shut-in period they are back produced. The difference between their arrival times yields information about S_{or}. Currently, they are broadly used for residual oil saturation assessment after the injection of low salinity brine (*Al Shalabi et al., 2017*). For the most part they are conducted in single phase flow cases.

- **Partitioning Interwell Tracer Testing (PITT)**: Tracers are injected and produced from different wells (two or more). Difference in their arrivals, breakthrough time etc. are the sought parameters. Within the oil industry SWCT have been more broadly used throughout the years. Apparently, the less amount of time required was the chief reason. While PITTs require some years depending on injection rate and distance between the wells, SWCT may be finished in only a few weeks (*Sharma et al., 2014*). PITTs have been successfully used in groundwater remediation projects. This project refers to Partitioning Interwell Tracer Testing. (*Dugstad et al., 2013*). Determination of residual saturation, flow patterns, sweep efficiency, directional flow trends are the key goals of this kind of tests.

As chemical compounds, tracer should not affect the properties of their solvent (water) such as viscosity or density. In all commercial simulators, tracers are considered to have no effect at all on reservoir fluid properties.

2.2. Reservoir Simulation

The chief idea of Reservoir Simulation is the solution of a Partial Differential Equation (PDE) which represents conservation of mass or energy within the porous media, numerically; by utilising an iterative method over time (time discretisation), after the reservoir has been split into grid blocks (spatial discretisation).

Hence, a differential equation is approximated with a difference equation, where derivatives are replaced by differences. In case of a Finite Difference Scheme (*Heriot Watt, 2013*):

$$(\frac{dP}{dx})_i = \frac{P_{i+1} - P_i}{\Delta x}$$

Regarding which actual difference is used, that is the forward (like the previous example, also called explicit), or the backward (or implicit where the difference of $P_i - P_{i-1}$ is used), numerous alternatives exist.

What is important to bear in mind is that an iterative method such as Newton- Raphson is an approximation and when an analytical solution exists it is crucial to compare those two, as the former exhibits an error. This error is related to the very idea of an iterative method. For instance, most of them start with a Taylor Series Expansion, where all higher order terms are neglected. Instantly, this causes the rise of an error.

What is more, numerical dispersion (or diffusion) can deteriorate the results of a simulation project. It can be abrupt in coarse grids. For instance, for a 1-D grid and a water flooding process, breakthrough time constantly changes if coarse grids are used. In a 2x1x1 grid water breakthrough would occur in 2 time steps, whereas in a 10x1x1 grid in ten time steps. If a time step is selected as 1 day or more (Δt = 1 day) one can easily realise the huge difference between those two.

Hence, in every simulation project it is crucial to define the grid size efficiently. The optimal size is descripted as the smallest possible in which numerical dispersion is limited (in terms of the properties that are sought) and more inexpensive as far computational time is concerned.

However, there are some inherent types of numerical dispersion that cannot be always tackled sufficiently, such as the one illustrated below. In case of a representation of a quarter of a five-spot pattern, injection and production wells are located at the opposite corners of a rectangular grid.

In a simulator though, flow across the diagonal where the two wells lie is prohibited, and only occurs up- down and left- right, respectively.

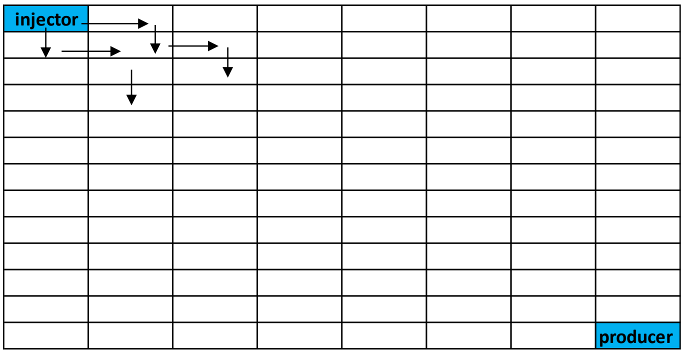

Figure 2.1: Inherent numerical dispersion in a quarter of a 5-spot pattern.

Such a pattern is prone to exhibiting errors, such as a delayed front by virtue of the inability of flow across the diagonal. The very reason behind this is the simplified permeability tensor. In a 3D system:

$$K = \begin{bmatrix} k_{xx} & 0 & 0 \\ 0 & k_{yy} & 0 \\ 0 & 0 & k_{zz} \end{bmatrix}$$

Values of permeability that would render flow across the diagonal possible (such as k_{xy}, k_{xz}, k_{yz}) exhibit a value of zero normally. The fully expanded permeability tensor is diagonalised in order to reduce the number of required calculations (*Gupta et al., 2001*).

Another useful aspect of simulation and the utilisation of finite differences is the averaging of reservoir properties. Let us consider two neighbouring blocks (i) and (i+1) at the implementation of Darcy's law:

$$Q = -\frac{k_i\, A_i}{\mu} \frac{P_f - P_i}{\frac{\Delta x_i}{2}}$$

$$Q = -\frac{k_{i+1}\, A_{i+1}}{\mu} \frac{P_{i+1} - P_f}{\frac{\Delta x_{i+1}}{2}}$$

Where P_f is the reference pressure at the contact of the two neighbouring blocks. Hence:

$$P_{i+1} - P_i = -\frac{Q * \mu}{2} \left(\frac{\Delta x_{i+1}}{(kA)_{i+1}} + \frac{\Delta x_i}{(kA)_i} \right) \rightarrow$$

$$\overline{k * A} = \frac{\Delta x_{i+1} + \Delta x_i}{\frac{\Delta x_{i+1}}{(kA)_{i+1}} + \frac{\Delta x_i}{(kA)_i}}$$

The latter is simply the harmonic average weighted by grid block sizes. The type of average being used is essential for one to realise the calculation being carried out by the simulator. For instance, for values k_1= 1000 mD and k_2= 2 mD a simple average between those two would yield 501 mD whereas the harmonic average a value of 3.99 mD.

The key idea towards how simulation is being carried out can be represented as follows. Let us consider a two-phase flow in a 1D system. To simplify things zero capillary pressure and elimination of gravitational effects have been assumed.

Simplified 1D Pressure equation can be descripted by:

$$\frac{\partial}{\partial x}\left(\frac{k_o}{\mu_o}(S_o) * \frac{dP}{dx}\right) + \frac{\partial}{\partial x}\left(\frac{k_w}{\mu_w}(S_o) * \frac{dP}{dx}\right) = 0 \qquad \{1\}$$

Similarly, saturation equation is descripted by:

$$\varphi * \left(\frac{\partial S_o}{\partial t}\right) = \frac{\partial}{\partial x}\left[\frac{k_o}{\mu_o}(S_o)\left(\frac{\partial P}{\partial x}\right)\right] \qquad \{2\}$$

By applying finite differences:

$$\{1\} \rightarrow \quad \frac{[M_\tau \ (S_o) \ (\frac{\partial P}{\partial x})]_{i+\frac{1}{2}} - [M_\tau \ (S_o) \ (\frac{\partial P}{\partial x})]_{i-\frac{1}{2}}}{\Delta x} = 0$$

Where M_τ is the sum of oil and water mobility terms.

$$\frac{[M_\tau\ (S_o)\ (\frac{P_{i+1}^{n+1} - P_i^{n+1}}{\Delta x})]_{i+\frac{1}{2}} - [M_\tau\ (S_o)\ (\frac{P_i^{n+1} - P_{i-1}^{n+1}}{\Delta x})]_{i-\frac{1}{2}}}{\Delta x} = 0$$

The non-linear term of mobility may be selected either at the current time step (**n**) or the following time step (**n+1**). By selecting the second alternative:

$$\frac{\left[M_\tau\ \left({S_o}^{n+1}\right)_{i+\frac{1}{2}}\left(P_{i+1}^{n+1} - P_i^{n+1}\right)\right] - \left[M_\tau\ \left({S_o}^{n+1}\right)_{i-\frac{1}{2}}\left(P_i^{n+1} - P_{i-1}^{n+1}\right)\right]}{\Delta x^2} = 0$$

$$\frac{[\,M_\tau\ \left({S_o}^{n+1}\right)]_{i-\frac{1}{2}}}{\Delta x^2} * P_{i-1}^{n+1} + \left\{\frac{[M_\tau\ \left({S_o}^{n+1}\right)]_{i+\frac{1}{2}}}{\Delta x^2} - \frac{[M_\tau\ \left({S_o}^{n+1}\right)]_{i-\frac{1}{2}}}{\Delta x^2}\right\} * P_i^{n+1} + \frac{[M_\tau\ \left({S_o}^{n+1}\right)]_{i+\frac{1}{2}}}{\Delta x^2} * P_{i+1}^{n+1} = 0 \qquad \{1\}$$

The non-linearity occurs because besides the unknown pressures, mobility terms also depend on the unknown saturations.

Respectively:

$$\{2\} \rightarrow\ \varphi\left(\frac{S_o^{n+1} - S_o^n}{\Delta t}\right) = \frac{[\frac{k_o}{\mu_o}\ (S_O)\ \left(\frac{\partial P}{\partial x}\right)]_{i+\frac{1}{2}} - [\frac{k_o}{\mu_o}\ (S_O)\ \left(\frac{\partial P}{\partial x}\right)]_{i-\frac{1}{2}}}{\Delta x}$$

$$\varphi\left(\frac{S_o^{n+1} - S_o^n}{\Delta t}\right) = \left[\frac{\frac{k_o}{\mu_o}\ \left({S_O}^{n+1}\right)_{\,i+\frac{1}{2}}}{\Delta x^2} * \left(P_{i+1}^{n+1} - P_i^{n+1}\right)\right] - \left[\frac{\frac{k_o}{\mu_o}\ \left({S_O}^{n+1}\right)_{i-\frac{1}{2}}}{\Delta x^2} * \left(P_i^{n+1} - P_{i-1}^{n+1}\right)\right]$$

$$S_o^{n+1} - S_o^n - \frac{\Delta t}{\varphi}\left\{\left[\frac{\frac{k_o}{\mu_o}\ \left({S_O}^{n+1}\right)_{\,i+\frac{1}{2}}}{\Delta x^2}\ \left(P_{i+1}^{n+1} - P_i^{n+1}\right)\right] - \left[\frac{\frac{k_o}{\mu_o}\ \left({S_O}^{n+1}\right)_{\,i-\frac{1}{2}}}{\Delta x^2}\ \left(P_i^{n+1} - P_{i-1}^{n+1}\right)\right]\right\} = 0 \qquad \{2\}$$

At this point two strategies can be followed.

The first one is the so called IMPES scheme. Mobility terms are approximated at the previous time step (n). By utilising S_o^n values an approximation would be obtained with regards to the unknown pressures. Subsequently, by utilising both approximations in the saturation equation {2}, the unknown saturations will be obtained at the next time step (n+1). Since the previous time step values were used for the calculation of the next one an explicit scheme is used regarding saturation. Eventually, by substituting the saturations at (n+1) time step in the pressure equation {1}, the pressure values at (n+1) time step can be obtained; this time implicitly however. Thus, an initially non-linear problem was linearized by taking an approximation at the previous time step.

Alternatively, an iterative method such as Newton-Raphson can be applied in the non-linear set of equations.

Pressure equation like before is:

$$\frac{[\,M_\tau\ \left({S_o}^{n+1}\right)]_{i-\frac{1}{2}}}{\Delta x^2} * P_{i-1}^{n+1} + \left\{ \frac{[M_\tau\ \left({S_o}^{n+1}\right)]_{i+\frac{1}{2}}}{\Delta x^2} - \frac{[M_\tau\ \left({S_o}^{n+1}\right)]_{i-\frac{1}{2}}}{\Delta x^2} \right\} * P_i^{n+1} + \frac{[M_\tau\ \left({S_o}^{n+1}\right)]_{i+\frac{1}{2}}}{\Delta x^2}$$

$$* P_{i+1}^{n+1} = 0 \qquad \{1\}$$

The saturation equation:

$$S_o^{n+1} - S_o^n - \frac{\Delta t}{\varphi} \left\{ \left[\frac{\frac{k_o}{\mu_o}\ \left({S_o}^{n+1}\right)_{\ i+\frac{1}{2}}}{\Delta x^2} \left(P_{i+1}^{n+1} - P_i^{n+1}\right) \right] - \left[\frac{\frac{k_o}{\mu_o}\ \left({S_o}^{n+1}\right)_{\ i-\frac{1}{2}}}{\Delta x^2} \left(P_i^{n+1} - P_{i-1}^{n+1}\right) \right] \right\}$$

$$= 0 \qquad \{2\}$$

The unknowns are pressure and saturation values at each grid block P_i^{n+1}, S_i^{n+1}. Hence:

$$S^{n+1} = \begin{bmatrix} S_1^{n+1} \\ S_2^{n+1} \\ S_3^{n+1} \\ \dots \\ S_{i-1}^{n+1} \\ S_i^{n+1} \\ S_{i+1}^{n+1} \\ \vdots \\ S_{mx}^{n+1} \end{bmatrix}, \qquad P^{n+1} = \begin{bmatrix} P_1^{n+1} \\ P_2^{n+1} \\ P_3^{n+1} \\ \dots \\ P_{i-1}^{n+1} \\ P_i^{n+1} \\ P_{i+1}^{n+1} \\ \vdots \\ P_{mx}^{n+1} \end{bmatrix}$$

Where *mx* is the grid block size. All the unknowns can be written together as:

$$X^{n+1} = \begin{bmatrix} S_1^{n+1} \\ P_1^{n+1} \\ S_2^{n+1} \\ \dots \\ S_i^{n+1} \\ P_i^{n+1} \\ S_{i+1}^{n+1} \\ \dots \\ S_{mx}^{n+1} \\ P_{mx}^{n+1} \end{bmatrix}$$

Consequently, Newton-Raphson is being implemented as:

$$X^{n+1\,(v+1)} = X^{n+1\,(v)} + [J(X)^v]^{-1} * F(X^v)$$

Where J is the Jacobian matrix and F are simply the equations {1} and {2}.

It goes without saying, that this was a simple case rather than a typical reservoir engineering problem. However, even in a 3D system with three-phase flow and abrupt non-linearity those basic principles are still valid. Other issues or a more detailed description about similar issues of simulation will be given in the ensuing chapters that refer to the conducted simulations runs. At this point a brief info about the simulators that were used will be given instead

2.2.1. Schlumberger ECLIPSE

ECLIPSE 100 is a fully implicit, three-phase, black-oil finite-difference reservoir simulator. ECLIPSE 300 is the compositional simulator of Schlumberger. Grid blocks can be either Cartesian or Radial with corner-point or block-centred geometry. The Newton-Raphson iterative method is solved at each time step and for each block, and the Jacobian matrix is fully expanded in all variables to ensure quadratic convergence. Its core is written in FORTRAN and it was the major simulator in this thesis. The 2010.1 version of Schlumberger's ECLIPSE was used.

By default in every run the fully implicit method is used, which is totally stable and ideal for difficult problems. It provides the opportunity of large time steps. In order to save up time the IMPES method (as briefly descripted before) may be used, in simple cases of history matching.

The total number of linear and non-linear iterations per time step can be modified by user through *tuning* and *nupcol* keywords respectively.

At each Newton iteration a linear equation of the following form is being solved.

$$A * x = b$$

$$\frac{dR}{dx} * x = \frac{dM}{dt} + F + Q$$

$$R = \frac{dM}{dt} + F + Q$$

Where dR/dx is the Jacobian matrix and b the non-linear residual. (In the example presented above, the non-linear residual comprises the coefficients such as mobility ratio that depend upon an unknown value, such as P^{n+1} or S_o^{n+1}), F is the net flow rate into neighbouring grid blocks and Q is the net flow rate into wells during the time step.

If the elements of b are summed over cells then obviously F will cancel and the sum corresponds to the rate of mass accumulation in the reservoir. ECLIPSE then computes an initial approximate solution.

The material balance error (mass accumulation term) is computed by summing the elements of the residual.

The primary solution variables X are pressure P and saturation. For a two-phase black oil study:

$$R = \begin{bmatrix} R_o \\ R_w \end{bmatrix} \quad X = \begin{bmatrix} P \\ S_w \end{bmatrix}$$

$$and\ J = \frac{dR_i}{dx_j} = \begin{bmatrix} \frac{dR_o}{dP} & \frac{dR_o}{dS_w} \\ \frac{dR_w}{dP} & \frac{dR_w}{dS_w} \end{bmatrix}_{ij}$$

The mass term can be calculated as:

$$dM = M_{t+dt} - M_t$$

$$M = PV * \begin{bmatrix} \frac{S_o}{B_o} \\ \frac{S_w}{B_w} \end{bmatrix}$$

Where *PV* is the pore volume of the grid block and B_o and B_w oil and water formation volume factors, respectively.

2.2.2. UTCHEM Chemical Flood Simulator

Devised at *The University of Texas at Austin* UTCHEM is a 3D multicomponent chemical simulator. It may be used as a typical black oil simulator although its key strength is in the application of chemical flooding with polymers or surfactants, tracer testing and water flooding processes. Its primarily chemical orientation is apparent from the requested parameters. Apart from the normal properties necessary to every black oil model simulator (such as grid size, fluids' PVT, reservoir properties and well data) by default UTCHEM requests several chemical parameters. So although all the parameters inserted in ECLIPSE were also introduced in UTCHEM (apart from those controlling the maximum number of linear and non-linear iterations), several parameters were used exclusively in the latter (see *APPENDIX C*).

The mass conservation equations are totally comparable with the ones used in ECLIPSE. Such an equation is described below:

$$\frac{\partial}{\partial t}\left(\varphi\,\widetilde{C_k}\,\rho_k\right) + \nabla\cdot\left[\sum_{l=1}^{n_p}\rho_k\,\left(C_{kl}\vec{u}_l - \vec{\vec{D}}_{kl}\right)\right] = R_k$$

Where *l* represents each one of the up to four phases (oleic, aqueous, microemulsion and gas), *k* denotes the component for which the conservation of mass is used (such as tracer components), $\widetilde{C_k}$ is the overall volume of component *k* per unit volume and R_k is the well-known residual term for component *k*.

D_{kl} denotes the dispersion term for each component *k* in the corresponding phase *l*. This term utilises the molecular diffusion coefficient (units are ft^2/day) over tortuosity which as it will be shown later is also present in the analytical solution of the conservative tracer concentration as well as the longitudinal and transverse dispersivities. The usage of such a term is advantageous for the user, as the effects of numerical dispersion can be further tackled by deliberately adjusting the degree of physical dispersion.

2.3. Numerical Methods of PITT

Throughout the years tracers have been used in the Petroleum Industry as a means of reservoir description and characterisation.

From a qualitative point of view, the tracer concentration curve yields implications in terms of connectivity between the wells, the existence of heterogeneity such as a thief zone or the identification of flow barriers. Conclusions of this kind will be presented in the following chapters that are dedicated to the implementation of tracer testing in a simulator.

Furthermore, numerous numerical techniques have been devised since their introduction. The corresponding tracer concentration curve may be used in order to estimate residual oil saturation (S_{OR}), sweep efficiency and fluid velocities.

In a PITT, tracers can be injected either as slugs (where they are introduced in the reservoir along water in a predetermined amount of time) or continuously (where their injection time is equal to that of the water; throughout the testing time). In the current project the former type of testing was conducted. When a pulse is injected, tracer concentration observed in the producing well exhibits a distributed curve due to water movement in the porous media through a distribution of flow paths and different flow rates (therefore velocity) in each path (*Alramadhan et al., 2015*).

The most powerful tool in terms of estimating the oil volume within the porous media is the so-called *Method of Moments.* Articulated by *Himmelblau and Bischoff (1968)* for a single-phase nonreactive flow in a packed bed the pore volume is given by the dimensionless mean residence time ($\bar{t}_D$) calculated from the tracer response curve from the implementation of an instantaneous tracer pulse:

$$\bar{t}_D = \frac{\int_0^\infty t_D \, C_D(t_D) \, dt_D}{\int_0^\infty \, C_D(t_D) \, dt_D}$$

$$C_D = \frac{C - C_{initial}}{C_{injected} - C_{initial}} \; , \quad t_D = \frac{\int_0^t q \, dt}{V_p}$$

C_D is the dimensionless tracer concentration. Since the initial tracer concentration (before the testing) is assumed to be zero, dimensionless concentration is just the concentration of the tracer observed at the production well divided by the injected concentration.

Equivalently, t_D is the dimensionless time in which V_p is the pore volume and q the volumetric flow rate.

When the volume of the injected tracer is finite, the dimensionless volume of the vessel is the difference between the mean residence times of the input and output tracers' curves. If the input tracer concentration is constant with a dimensionless duration time of t_{Ds} (slug size) then the correlated mean residence time is given by:

$$(\,\bar{t}_D\,)_{correlated} = \bar{t}_D - \frac{t_{Ds}}{2}$$

In a permeable medium in which the flowing phases are N_p, the overall flux F_i and total fluid concentration C_i of component *i* are:

$$F_i = \sum_{j=1}^{N_p} f_j * C_{ij} \quad and \quad C_i = \sum_{j=1}^{N_p} S_j * C_{ij}$$

Where C_{ij} is the concentration of component i in the phase j, f_i is the fractional flow of phase j and S_j the saturation of phase j.

The residence time for component i is the inverse of the specific concentration velocity for component i and may be expressed by:

$$\bar{t}_{Di} = \frac{1}{v_i} = \frac{\partial C_i}{\partial F_i}$$

For a steady-state two-phase flow containing a nonadsorbing tracer component i which partitions between phases k and j the dimensionless time is:

$$\bar{t}_{Di} = \frac{C_i}{F_i} = \frac{S_j + S_k \, {K_{kj}}^i}{f_j + f_k {K_{kj}}^i}$$

${K_{kj}}^i$ is the partition coefficient of tracer i defined as the ratio of concentration of tracer i in phase k to that of phase j. It is assumed that ${K_{kj}}^i$ is independent of C_i and local equilibrium of tracer partitioning between phases exists. The latter expression is the cornerstone in terms of the tracer numerical techniques.

Let us consider a permeable porous medium exhibiting an average residual saturation of S_R and a constant water flow rate q. At time zero, a second water stream containing two nonadsorbing tracers is introduced at the injection well with a duration time of t_s. Tracers 1 and 2 have partition coefficients of K_1 and K_2. If the latter equation is applied for those two tracers:

$$\bar{t}_{D1} = S_w + S_R * K_1 \ \ \{1\} \quad and \quad \bar{t}_{D2} = S_w + S_R * K_2 \ \ \{2\}$$

$$Also \ \ S_w + S_R = 1 \quad \{3\}$$

There three equations for three unknowns; the two phases' saturations and the pore volume. The latter is expressed implicitly in:

$$V_p = \frac{q\,\bar{t}_1}{\bar{t}_{D1}} = \frac{q\,\bar{t}_2}{\bar{t}_{D2}} \quad \{4\}$$

$$\bar{t}_1 = \frac{\int_0^{t_f} t\, C_{D1}(t)\ dt}{\int_0^{t_f} C_{D1}(t)\ dt} - \frac{t_s}{2} \quad \{5\} \quad and \quad \bar{t}_2 = \frac{\int_0^{t_f} t\, C_{D2}(t)\ dt}{\int_0^{t_f} C_{D2}(t)\ dt} - \frac{t_s}{2} \quad \{6\}$$

The upper limit of integration is modified from infinity to t_f. This illustrates that the tracer test (water injection) lasts for a finite amount of time equal to t_f. In practice this is the very moment that tracer concentration is smaller than the detection limit.

Eventually the average oil residual saturation can be written as:

$$S_R = \frac{\bar{t}_2 - \bar{t}_1}{(K_2 - 1)\bar{t}_1 - (K_1 - 1)\,\bar{t}_2}$$

Equivalently, the swept pore volume may be written as:

$$V_p = \frac{q\,\bar{t}_1}{1 - S_R\,(1 - K_1)} = \frac{q\,\bar{t}_2}{1 - S_R\,(1 - K_2)}$$

For the most part, a conservative tracer is used along with non-conservative one(s). In this case K_1 is equal to zero and the saturation expression is modified as follows:

$$\boldsymbol{S_R} = \frac{\boldsymbol{\bar{t}_{part.}} - \boldsymbol{\bar{t}_{cons.}}}{(\boldsymbol{K_{part.}} - \mathbf{1})\boldsymbol{\bar{t}_{cons.}} + \boldsymbol{\bar{t}_{part.}}}$$

Mean residence times of the corresponding tracers are employed in the latter equation. In order to calculate the mean residence time though testing period needs to last until the 'cut-off' time t_f. Over the years several alternatives of residence time were utilised, to reduce the total test duration.

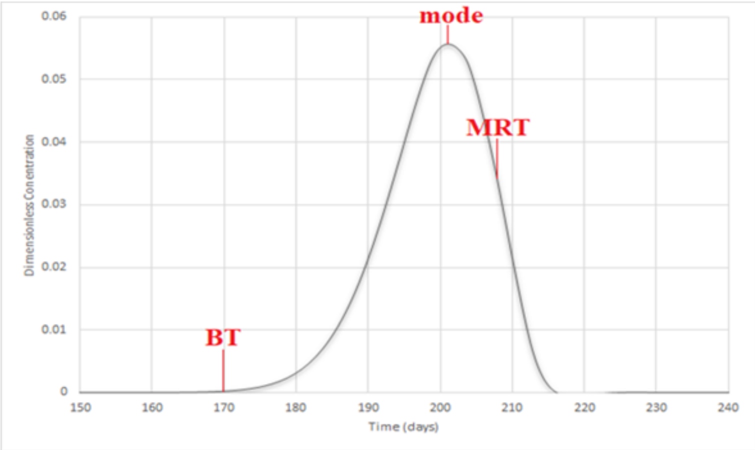

Figure 2.2: Schematic representation of the quantities being used in numerical methods.

These alternatives are **breakthrough time** (the first time at which a non-zero tracer concentration is observed), **mode time** (the time at which the maximum concentration lies) and the time step at which the 50 % of the total tracer recovery mass (**$t_{50\%}$**) occurs (for a constant injection rate of 200 stb/day and for slug injection time of 12 hours the latter is equal to 50 stb of tracer produced) (see **Fig. 2.1**).

With regards to the total testing period breakthrough time utilisation is the most advantageous. Yet, it heavily depends on the detection limits available and in most cases lacks in reliability. Particularly in a simulation run this value is prone to numerical dispersion, for the peak appears narrowed or broadened by virtue of dispersion. Mode time concentration acquires much more time than breakthrough one but once determined no need for the continuation of the test exists. If numerical diffusion is well restricted it is a very useful means for the calculation of average saturation and swept pore volume. It is usually calculated alongside the concentration corresponding to the 50 % of total tracer amount produced. Mean residence time on the other hand, is the most reliable technique. Ways of reducing the total testing time exist, such as extrapolating tracer concertation for after the peak is reached an exponential decay occurs. As it will be shown though, the time threshold at which an extrapolation of tracer date would yield realistic data is closer to the cut-off time rather than mode time; this way reducing the total testing period only a little. At any rate, it is the most expensive method as far as need of time is concerned.

When other time values (such as mode time) rather than the mean residence one are used often the saturation equation is presented as:

$$S_R = \frac{\frac{\Delta t}{t_{cons.}}}{\frac{\Delta t}{t_{cons.}} + K}$$

Δt is simply the difference between partitioning and non-partitioning corresponding times as before. What cannot be seen through the previous formulation is whether slug injection period is taken into account. The answer is affirmative, however it exhibits a variation than the term used with regards to mean residence time. That is, injection time should be reverted back at day zero. Hence, if tracers are injected at day three and last for one day, the corresponding time values have to be reduced by three days.

All the equations presented above are valid for 1D grids and for reservoirs exhibiting an irreducible oil saturation value. This explains why tracer testing's primary application is at the investigation of EOR techniques; that is at a later stage of production, after water flooding with remaining oil saturation close to S_{or}. However, practice indicates that they can be readily employed in 2D or 3D grids providing excellent results. Moreover, exactly the same formulations can be also applied for mobile oil cases (as a violation of the derivation showed above), for instance before the application of IOR methods such as water flooding. Of course, the obtained results would not be as accurate as for immobile oil but fair approximations may be received. Equations have also been produced that are specifically valid for mobile oil cases such as the one derived by Asakawa (2005):

$$S_o = \frac{\bar{t}_{part.} - \bar{t}_{cons.} - \frac{K_{part.}}{q_{prod}} \sum_{wells}(q \int_t^{\infty} f_o \, dt)}{\left(K_{part.} - 1\right)\bar{t}_{cons.} + \bar{t}_{part.}}$$

The volume of oil in this case is calculated as:

$$V_o = q_{prod} \frac{\bar{t}_{part.} - \bar{t}_{cons.}}{K} \sum_{wells} (q \int_t^{\infty} f_o \, dt)$$

Regarding a reservoir at its residual saturation, the latter term related to oil fractional flow is eliminated:

$$V_o = q_{prod} \frac{\bar{t}_{part.} - \bar{t}_{cons.}}{K}$$

Intentionally, the chemical character of the selected tracers is not investigated. In the selection of the tracers that will be used, partition coefficient is of great magnitude. For a passive tracer this is straightforward as they exhibit a zero value. In terms of active tracers however, a very small partition coefficient would unavoidable lead to little if any at all separation between the tracers. Similarly, a very high partition coefficient would prolong the test duration for no reason whatsoever. Hence as a rule of thumb the following inequality could be taken into consideration (*Alramadhan et al., 2015*):

$$0.2 \leq R = \frac{S_r K_i}{1 - S_r} \leq 3$$

The very time at which the tracer injection (with respect to water injection) will take place is also of importance. Of course, in cases of immobile oil it is of no use. Oil saturation is fixed at its residual value and throughout the water flooding period it remains constant. Concerning mobile oil cases however, oil saturation varies throughout the water injection. Usually, the same tracers are injected at various distinct times in order to be able to depict the 'wider' picture. Ideally, the first set of tracer slugs should be injected from the first day of water flooding, when oil saturation exhibits a value of $1\text{-}S_{wc}$ (or it is reduced by the amount of oil produced up to that time, for instance by virtue of depletion).

Finally, the formulations derived previously are valid under certain assumptions and conditions. In summary these are (*Asakawa, 2005*):

i) Saturation can vary with space. This is the cornerstone of this project where the S_o distribution effect is investigated. Briefly, this means that a reservoir that exhibits an average residual saturation of a certain value, locally may exhibit various saturation values. 'Locally' in reservoir simulation means per grid block. That is, the average residual saturation of a reservoir may be 0.15 for instance, but some blocks exhibit a value of 0.1 others of 0.2 etc.

ii) The fluids and porous media do not expand with time; at least as long as the PITT lasts. This means that constant porosity is necessary throughout the testing time.

iii) No mass transfer of tracers at the boundaries of the reservoir is allowed save the producing and injecting wells.

iv) Tracer partition coefficients are constant. Alterations in salinity, temperature and pressure may differentiate the partition coefficients and therefore, they are not taken into account. In a simulator this can be easily attained by defining the same partition coefficient value for a large pressure range.

v) Tracer decay, adsorption and reaction are neglected as well. In any case their effects are infinitesimal.

vi) Tracers do not occupy volume and do not alternate physical properties of the fluids. Those assumptions are made automatically by the simulators. The fact that tracers do not occupy volume may seem erroneous as it has already been said that the time at which 50 % of total injected tracer mass is taken into account. For a two-phase flow when a chemical compound is injected in the producer oil, water and barrels of this compound would be expected. A closer look at production data of a simulator would indicate that only water and oil is produced in reality and tracer produced volume is in fact a labelled water.

vii) The initial tracer concentrations (before the initiation of water injection) are zero.

viii) At the boundary between the formation and the wells, no diffusion is assumed.

3. 1D Model

Before proceeding to 2D or 3D models it is important to perform similar runs in a 1D grid. It is not just the fact that numerical methods are originally derived for 1D grids, for they can be easily applied for 2D and 3D models as well. Most importantly, an analytical solution of the tracer concentration response may be derived. Therefore, the curves generated by ECLIPSE and UTCHEM may be directly compared with the actual curve, fruit of the analytical solution. Hence, before simulating more complex grids it is highly beneficial to assess the operation of a simulator.

Tracer flow can be described by an advection- dispersion equation. Apart from the advection term that denotes the velocity of the solvent (water) by which tracers are transported, the dispersion term denotes the distribution of pore size, the subsequent varying velocities at the pore scale as well as the possible flow paths (*Hadley & Newell, 2014*). It also includes the molecular diffusion effect, in which molecules flow from areas of higher to lower concentration. Those two mechanisms result in the distribution of the tracer compound at the advancing front (*Lajeunesse et al. 2018*). For fluid (water) velocity close to zero, the diffusion term is the determining factor of tracer transportation. Many chemical and physical effects are related to tracer flow, such as diffusion, radioactive decay, adsorption and dispersion. While some can be neglected for specific study cases assuming ideal behavior (such as adsorption and decay) dispersion plays an important role. In order to identify its magnitude for a specific study case, the dimensionless *Peclet Number* is calculated. If the latter exhibits a non-zero value then dispersion effect is greater than diffusion. Subsequently, the dispersion coefficients as a function of Peclet Number should be computed. The conservation equation of a tracer may be expressed as (*Husebi et al., 2013*):

$$\frac{\partial}{\partial t}\left(\sum_{i=o,w,g} \varphi\, K_i\, S_i\, C\right) + \nabla\cdot\left(\sum_{i=o,w,g} u_{\,i} K_i\, C\right) - \nabla\cdot\left(\sum_{i=o,w,g} \varphi\, S_i \left(\frac{D_{m,i}}{\tau}\,\boldsymbol{I} + \dot{\boldsymbol{D}}_{\boldsymbol{i}}\right)\cdot\nabla\,(K_i C)\right) = 0$$

Where K_i is the partition coefficient of the tracer in each phase, S_i the phase saturation of each phase, $D_{m,i}$ the molecular diffusion coefficient of each phase, $\boldsymbol{I}$ the identity tensor and $\dot{\boldsymbol{D}}_{\boldsymbol{i}}$ the dispersion tensor. The latter among other parameters such as tortuosity comprises the longitudinal and traverse dispersivities that depend upon the solvent.

$$P_{ei} = \frac{u_i\, d}{D_{m,i}}$$

If the latter value is greater than zero, either due to high velocity or relatively small molecular diffusion coefficient which is usually the case, then the dispersion effect is enhanced. This physical (or mechanical) type of dispersion effects real experiments of tracers and the shape of tracer concentration stems from this effect.

For a conservative water tracer (K_w=1, K_o= K_w= 0) the conservation equation may be rewritten as:

$$\frac{\partial}{\partial t}\left(\varphi\, S_w C\right) + \nabla \cdot \left(u_w\, C\right) - \nabla \cdot \left(\varphi\, S_w \left(\frac{D_{m,i}}{\tau}\, \boldsymbol{I} + \dot{\boldsymbol{D}}_{\boldsymbol{i}}\right) \cdot \nabla\right) = 0$$

If such an equation is solved numerically then unavoidably numerically smearing problems occur. Several schemes (such 2nd or 3rd order equation with flux limiters) have been devised to reduce those smearing effects. The results of the numerical solution of such an advection-convection equation significantly deteriorate in case of a finite-difference approach (as used in a simulator) as the dimensionless Peclet number increases and numerical damping is broad (*Ahmed, 2012*).

If the tracers are injected as slugs they are supposed to have no effect on fluids flow within the reservoir. Moreover, the calculation of the dispersion coefficient is a tedious task and may only be attained with systematic experimental work.

For a relatively small value of Peclet Number –by using small fluid velocity and relatively high molecular diffusion coefficient- a 1D convection-dispersion equation may adequately describe the tracer transportation within the porous medium (*Husebi et al., 2013*):

$$\frac{\partial C}{\partial t} + u\, \frac{\partial C}{\partial x} - D_x\, \frac{\partial^2 C}{\partial x^2} = 0$$

D_x is the quotient of molecular diffusion coefficient (with units *length*^{2}*/time)* over tortuosity (τ). Its effect on the tracer response basically pertains to the narrowing or broadening equivalently, of the curve. In total, tracer flow is dependent upon the advection term (the transportation by virtue of solvent's velocity) and dispersion (in which the diffusion term is encompassed implicitly). In a finite difference approximation scheme a percentage of error is associated with numerical dispersion.

The initial boundary conditions may be written as:

$$C\ (x = 0, t) = \frac{M}{Q}\ \delta(t)$$

$$C\ (x, t = 0) = 0$$

$$\lim_{x \to \infty} C\ (x, t) = 0$$

The analytical solution can be subsequently written as:

$$C\ (x, t) = \frac{M}{Q}\ \frac{x}{\sqrt{4\pi\ D_x t^3}} \exp\left[-\frac{(x - ut)^2}{4\ D_x\ t}\right]$$

This solution may give the conservative tracer concentration for every x and t. In terms of the responding concentration at the production well (x = L):

$$C_p(t) = \frac{M}{Q}\ \frac{L}{\sqrt{4\pi\ D_x t^3}}\ \exp\left[-\frac{(L - ut)^2}{4\ D_x\ t}\right]$$

The value of the simplified dispersion coefficient is related to the chemical compound being utilised and many individual phenomena (including molecular diffusion). Since its value cannot be determined dispersion control was avoided in Eclipse. In terms of UTCHEM in which the value of the molecular diffusion coefficient over tortuosity (as well as the longitudinal and transverse dispersivity coefficients) is mandatory for each particular tracer, such a value was selected so that the maximum concentration of the curve generated by UTCHEM is equal to that of Eclipse. The same was applied in the analytical solution as well. In order to render the generated curves from the two simulators comparable between each other, the molecular diffusion coefficient that is introduced in UTCHEM exhibits a rather high value, for it also incorporates the dispersion effect of Eclipse. Eventually, the analytical solution as well as the curves obtained by UTCHEM and Eclipse exhibit the same maximum concentration (at mode time). The data being used for the simulation of the 1D model are presented in **Table 3.1**.

The first thing that has to be defined is the grid block number for a given reservoir. Starting for rougher grids one should proceed to finer ones that can eliminate numerical dispersion in the sought property (in this case this is tracer concentration response at the production well). Hence, starting from a 1x1x1 grid, gradually a 200x1x1 grid block is found as optimum **(Fig. 3.1)**. If the length of the reservoir is 100 feet (L=100 ft.) then each block exhibits a length of 0.5 ft. and the two wells are located at the two edges of the grid. However, Cartesian geometry is centre-blocked oriented which means that the total length between the producer and the injector is not *L* but *L-2*dx/2* where *dx* is the length of each block.

For a 1D grid and constant injection and production flowrate the velocity of water (which is equal to conservative tracer velocity) is:

$$u = \frac{Q^{r.c}}{A}$$

Wells are rate-controlled in stock tank barrels. Since oil is immobile only water is produced, then only water formation volume factor should be taken into consideration. Cross sectional area *A* is the product of *Ly* and *Lz* (dimensions over the y and z axis) with porosity and water saturation S_w. Porosity term is clear, as flow occurs in the pore rather than the bulk volume. Water saturation term is similar though; water flow takes place in the area that is not filled with residual oil. Hence:

$$u = \frac{Q^{s.c} * B_w}{L_y \, L_z \, \varphi \, S_w}$$

That is the velocity value that should be utilised in the analytical equation. L_y and L_z are the reservoir dimensions over the y and z axis, respectively. Their usage instead of block dimensions simply implies that water velocity is constant in every block since flow rate is fixed, y and z dimensions are the same for each block, and no oil is produced, so that cross sectional area remains constant as well.

The fact that everything is solved numerically in a simulator can be inferred from the velocity calculation. Should velocity (in Eclipse fluid velocity is generated for each individual block) of water is requested a similar but in any case different value will be given. However the proportional relationship between velocity and cross sectional area is valid. For instance if the height (*Lz*) of the reservoir is modified the ratio of velocities (the one reported by Eclipse over the analytical one) is equal to the ratio of the *Lz* values.

Furthermore, a simple application of Darcy law for single phase flow (S_w = 1) can indicate some variations. By utilising the data of **Table 3.1**:

$$u_x = -\frac{k_x}{\mu}\frac{\Delta P}{\Delta X}$$

$$u_x = -\frac{9.87 * 10^{-13}\,(m^2) * 2040.3\,\left({}^{kg}/_{m^2}\right)}{8 * 10^{-4}\left(N\frac{s}{m^2}\right) * 0.1525\,(m)} = 1.65\frac{m}{s} = 0.435\frac{ft}{day}$$

$$q\left(\frac{stb}{day}\right) = \frac{u_x * L_y * L_z * \varphi * S_w}{B_w} = 50.8\ stb/day$$

All the data being used in the previous formulations are well known, save for the pressure difference between the wells. By adjusting a constant (surface) flowrate, an injection as well as a production bottomhole pressure is generated by the simulator itself. What the previous formulation points towards is that although the production rate was set at 50 stb/day by using the generated pressure difference by the simulator in the well-known Darcy's law, it will reproduce a different flowrate; in this case 50.8 stb/day.

The results obtained from Eclipse and UTCHEM in comparison with the analytical solution are illustrated in **Fig. 3.2**.

If the relative position of peak-concentrations with respect to the analytical one are examined, UTCHEM gives an infinitesimal variation of just 0.6 %, whereas Eclipse is slightly offset to the right hand side with a total variation of 2 %; which at any rate is acceptable. A closer result to the exact solution is attained in UTCHEM by virtue of its higher order of accuracy scheme in the tracer solver. Lower order schemes are said to be highly prone to numerical dispersion (*UTCHEM Technical Documentation*). On the other hand, total variation diminishing schemes are able to address numerical dispersion. Higher order of accuracy of the latter can restrict adequately the effect of numerical dispersion. Should the implicit schemes fail to provide a realistic solution, explicit discretisation is used in most cases. However, this should be done with extra caution, for unphysical values may be obtained in terms of pressure etc.

Several schemes were utilised in terms of Eclipse, such as increasing the total number of linear and tracer iterations, implementing a 2nd order limiting scheme (as descripted before), varying the slug duration and reducing the time step size. All of those did not manage to produce any beneficial effect. Particularly the latter (time step size) is related to numerical dispersion. Smaller time step is beneficial for sharpening the peak and hence restricting dispersion, but cannot offset the corresponding curve. As far as Eclipse is concerned the Cascade Algorithm for tracers was used. Also, a number of very small initial time steps (0.001 days) was beneficial in order to facilitate convergence.

It may seem peculiar why the analytical solution cannot be used in 2D cases or even 3D, simply by expanding the formulations over the y and z directions as well. In every run a quarter of a five-spot pattern was illustrated. As shown previously, when the two wells are located across the diagonal neither the total length (as flow in the diagonal occurs vicariously rather than directly) nor velocity (for cross sectional area is not constant) can be defined.

Figures of chapter 3

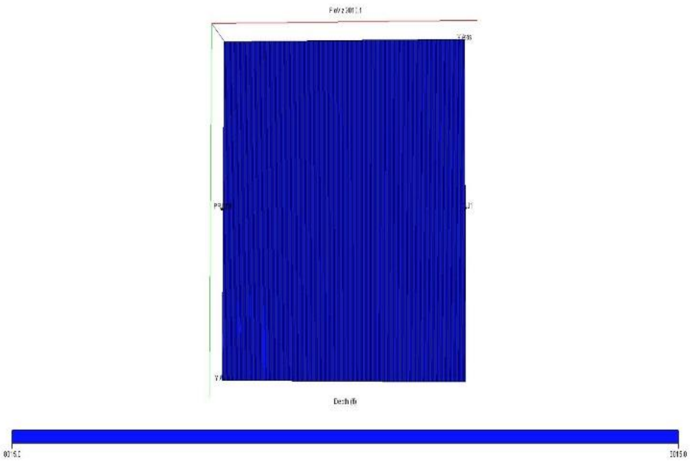

Figure 3.1: Grid of 200x1x1 blocks, being used in the 1D model.

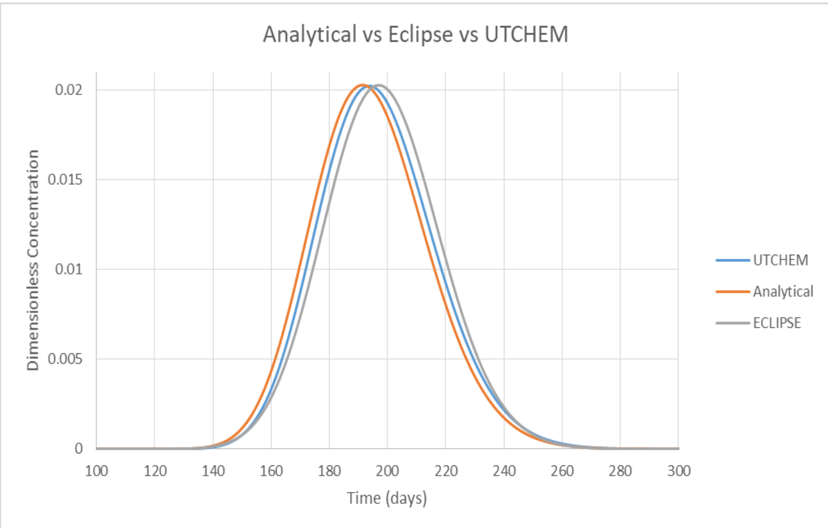

Figure 3.2: Tracer concentration response obtained by Eclipse, UTCHEM and the analytical solution.

Tables of chapter 3

1D model	
No. of blocks in x direction	200
No. of blocks in y direction	1
No. of blocks in z direction	1
datum level	8030 ft.
D_x (per block)	0.5 ft.
D_y (per block)	100 ft.
D_z (per block)	30 ft.
Reservoir depth	8000 ft.
porosity (constant)	0.25
X permeability	1000 mD
Y permeability	1000 mD
Z permeability	100 mD
water saturation (S_w)	0.75
Residual Oil Saturation (S_{or})	0.5
oil density	49 ppg
water density	63 ppg
water compressibility	3E-06 1/psi
rock compressibility	4E-06 1/psi
B_w	1.02
reservoir pressure	4500 psi
Production rate	50 stb/day
Injection rate	50 stb/day
wellbore radius	4 inches

Table 3.1: Data set for 1D study case.

4. Residual Oil Study

The second part of the current thesis is related to residual oil cases implemented in a 2D grid. A sensitivity analysis was carried out with respect to oil distribution variations for various wettability systems. Particularly, four different wettability systems were simulated; from a water wet to a strongly oil wet system. What is meant by oil-wet or water-wet is chiefly the very value of residual oil saturation (S_{or}). Since oil is immobile the importance does not lie within the relative permeability values of oil (or water) saturations but at which saturation oil exhibits a zero relative permeability.

First, a brief discussion should be made regarding the data being utilised.

4.1. Data Set Review

In this study a 1000x1000x 90 (ft.^{3}) reservoir was used. For a rectangular type of grid that resembles a quarter of a five-spot pattern (the two wells are located at opposite corners) the diagonal that connects the two wells is $1000\ ft * \sin(\pi/4)\ \approx 1414\ ft$. At the same time a small fluid (water) velocity should be used (lower than 1 ft/day), to avoid possible errors. Those errors are associated with numerical dispersion. Hence, flowrate needs to be restricted. Apart from a fine grid also small time step implementation retains numerical dispersion limited. Even if the extra computational time can be afforded though (in terms of hardware and generally time) particularly Eclipse offers at maximum 1000 time steps per individual run. Hence, in order to facilitate the flow of water and eventually tracers themselves, increased high (absolute) permeability values are essential. Thus, a 1000 mD value was utilised regarding permeability towards the x and y directions, whereas a 100 mD value was given to permeability towards the z axis.

Lying at the depth of 8000 ft. a representative reservoir pressure of 4500 psi was implemented. Wellbore radius was selected at 0.3333 ft. depicting a typical 4-inch production tubing. In order to restrict water velocity, a flowrate of 1500 stb/day was used for both the injection and production well. The only restriction implemented in the production well is that bottomhole pressure should not drop below the hydrostatic one at 8000 ft. For water density of 63 ppg, hydrostatic pressure at that depth is approximately 3500 psi.

Seven tracers were used at most (one passive and six partitioning with various partition coefficients) that are injected at day one for a 1-day period. Since only water flows, it does matter in reality the time at which tracer injection begins, for oil saturation remains constant throughout the injection period. Delaying the tracer injection in this case, simple enhances the need for redundant computational time.

The several wettability systems will be presented below per specific case. All the data being used are identical to the ones in **Table 3.1**, in terms of a 2D grid however.

4.2. Grid Definition

Every reservoir simulation task begins with the proper grid selection according to the sought-property. In this case, this is tracer concentration at the producer. Given the size of the reservoir, starting from coarser grids a 500x500x1 grid was found as optimal. The concentration curves of the passive tracer for several grid sizes are presented in **Fig. 4.1**.

Apart from the sharpening of the concentration curves as the number of grid blocks is increased, a relative offset as well may be observed towards the left hand side. This leftwards offset means that either water velocity (and hence tracers' as well) is increased or that the total length between the producer and the injector is reduced. In terms of the latter, exactly the opponent occurs as grid becomes finer due to the use of block-centred geometry, but as already explained flow across the diagonal is prohibited. Instead, for a 2D grid flow takes place in a left-right and up-down fashion. If the grid is refined across the x and y directions, velocity across those directions is increased due to the reduction of the cross sectional area. This causes an increased inter-block water velocity in a finer grid, regardless the fact that the diagonal at the corners of which the injector and producer are located, increases.

4.3. Study per Case

After the grid selection, various wettability systems were used. These are: a water-wet system (S_{OR} = 0.3), a mixed system (S_{OR} = 0.5) a water-wet system (S_{OR} = 0.6) and a strongly water- wet system (S_{OR} = 0.7). Data are utterly synthetic and the corresponding residual saturation values may not align with reality. The importance though, is to examine the simulators and the analytical techniques themselves and so their usage is not in reality a violation. As already stated wettability herein is only related to residual oil saturation value. Hence, an oil-wet system that has a greater affinity with oil which remains trapped in the porous media would exhibit a higher S_{OR} value than a water-wet reservoir. The relative permeability curves are presented in **Figs. 4.2, 4.3, 4.4, 4.5.**

4.3.1. Water-Wet Reservoir

Two different uniform oil saturation values were used in this study; a 0.25 and 0.30 S_o, respectively. Since, S_{OR} at this system is 0.3 both saturation ensure that oil remains immobile. In total 7 different tracers were injected (from day 1) with partition coefficients of 0, 0.5, 1, 1.5, 1.8, 3, 4. The higher the partition coefficient of a tracer the greater its retardation. Hence, higher time step was implemented in order to determine the various required time values of the active tracers exhibiting high partition coefficients.

Apart from the Mean Residence Time, Mode Time, Breakthrough Time and the time that corresponds to 50% of total tracer recovery ($t_{50\%}$) were utilised. Their results are presented in **Tables 4.1-4.2** alongside the corresponding swept pore volumes. The corresponding tracer concentration curves for oil saturation of 0.25 are presented in **Fig. 4.6**. The higher the partition coefficient the greater the retardation and hence the more the computation time acquired.

The use of both Mode Time and $t_{50\%}$ give similar results with respect to the oil saturation prediction; 10.5 % and 9.5% variation for the 0.25 and 0.35 S_{OR} cases, respectively. The reported error is related to the time step size. So that for a 3-day time step and mode times of passive and active tracers A and B respectively the error (%) is calculated as:

$$E_{1,2,3,4} = \frac{\frac{\left(t_{part} \pm 3\right) - \left(t_{cons} \pm 3\right)}{\left(t_{cons} \pm 3\right)}}{\frac{\left(t_{part} \pm 3\right) - \left(t_{cons} \pm 3\right)}{\left(t_{cons} \pm 3\right)} + K_d}$$

Four distinct values are obtained and the error is found as:

$$Error\ (\%) = \frac{\max\left(E_{1,} E_{2,} E_{3,} E_4\right) - \min\left(E_{1,} E_{2,} E_{3,} E_4\right)}{\max\left(E_{1,} E_{2,} E_{3,} E_4\right)} * 100\%$$

From the formulation it can be inferred that the higher the partition coefficient the lower the total error will be. This error though, is primarily statistical and the use of smaller time step does not mean that necessarily a better prediction will be obtained.

As far as Breakthrough Times are concerned, they tend to exhibit the highest variations with respect to their oil saturation predictions. For instance, the usage of a K_d equal to 0.5 may provide an accurate estimation while a K_d equal to 2 can be totally irrational. In fact, it is the most unreliable time set that can be used for breakthrough times are susceptible to numerical diffusion. For instance, by implementing a finer grid, mode time will be found to exhibit a very similar value as before, whereas breakthrough time will be completely different. Also, if dispersion effects were totally eliminated the observed breakthrough time would in reality be the mode time, with dimensionless concentration equal to 1.

Mean Residence Time in terms of S_o prediction provide results similar to mode and $t_{50\%}$ times. However, if extrapolation is used from a very early point (that is smaller time step is used) the results will be abysmal. In the case of 0.25 uniform S_o saturation, if time steps of 5, 12 and 18 days are used respectively in the calculation of Mean Residence Times, predictions tend to exacerbate for higher time steps. After 50 small initial time steps that facilitate convergence another 950 steps of the corresponding values are used (see **APPENDIX**). Value of 1000 corresponds to the maximum number of time steps allowed by Eclipse. Extrapolation is conducted afterwards to estimate the remaining $C*t$ and C terms from t_b (final time step in the simulator) to infinity. Small enough time step that leads to a heavier dependence in extrapolation deteriorated the results. If extrapolation is performed at a more advanced time level it can provide descent results.

Let us stick to how extrapolation is conducted in Mean Residence Time calculations. After the peak concentrations and if not heterogeneities occur (that may lead to several peak-concentrations) the concentration curve exhibits an exponential decay. This can be verified in a semi-log plot of concentration versus time, if C exhibits a linear trend. Mathematically, after t_b tracer response can be expressed as (*Pope et al 1994*):

$$C = C_b * e^{-\frac{(t-t_b)}{a}}$$

1/a is the slope of the straight-line portion of the curve. Then Mean Residence Time may be calculated as:

$$\overline{t} = \frac{\int_o^{t_b} C * t\, dt + \int_{t_b}^{\infty} C * t\, dt}{\int_o^{t_b} C\, dt + \int_{t_b}^{\infty} C\, dt} - \frac{t_{slug}}{2}$$

$$\overline{t} = \frac{\int_o^{t_b} C * t\, dt \; + \; a\,(a + \; t_b)\, C_b}{\int_o^{t_b} C\, dt \; + \; a * C_b} - \frac{t_{slug}}{2}$$

$$\overline{t} = \frac{\int_o^{t_b} C * t\, dt \; + \; \frac{b}{a^2} * e^{-at_b}\,(1 + at_b)}{\int_o^{t_b} C\, dt \; + \; \frac{b}{a}\; e^{-at_b}} - \frac{t_{slug}}{2}$$

Integrals, representing the area of the concentration versus time plot, can be approximated in a spreadsheet fashion with *dt* time intervals.

$$\overline{t} = \frac{\sum_i^{t_b}(C_i * t_i * \Delta t_i) + \; \frac{b}{a^2} * e^{-at_b}\,(1 + at_b)}{\sum_i^{t_b}(C_i * \Delta t_i) + \; \frac{b}{a}\; e^{-at_b}}$$

Apart from the classical Δt_i, approach other methods may be applied as well such as Simpson's Rule (used in chromatography), which may accelerate the calculations by utilising fewer time step values. Since, all data are obtained from the simulator it does not really matter which technique is used for the integral approximation.

Particularly in Mean Residence Time calculations the available detection limits of tracer concentrations are important. In reality, dimensionless concentrations at the order of E-13 can be detected at best. In practice one would have to make do with much smaller values, for testing period is reduced as much as possible due to financial purposes. The available detection limits of Eclipse are E-20 and from a value greater than E-10 extrapolation may be conducted safely.

In the analytical solution though (in a 1D reservoir) detection limit is set by the user (decimal precision of the spreadsheet). Hence, even values of E-300 can be observed. Calculating the integral in cases where detection limit is E-20 and respectively with E-300 yields infinitesimal variation. The E-20 detection limit provided by Eclipse is more than enough.

As a rule of thumb, *retardation factor R* which is equal to the product of partitioning to the non-partitioning mean residence time should be greater than 1.2 (*Dwarakanath et al., 1999*) in order to restrict relative errors below 10%. Corresponding *R* values are incorporated to the results of Mean Residence Time.

The results of the numerical techniques of the different wettability systems for the various saturation distributions are analyzed together in *subchapter 4.4*.

4.3.2. Neutral Wettability Study

In this study two average oil saturations were selected; at 0.25 and 0.35 respectively (from the corresponding relative permeability curve it can be seen that residual oil saturation is 0.4). Apart from using each one of those values per block (for a 500x500x1 grid, each one of the 250.000 blocks exhibits 0.25 or 0.35 S_o) several distribution patterns were created. These are illustrated in **Figs. 4.7-4.11.** The average value of all of those distributions is either 0.25 or 0.35 of S_o (or equivalently 0.75 and 0.65 in terms of water saturation).

Each one of those values utilised per block should exhibit a zero oil relative permeability (water relative permeability should not be necessarily 1 though). Otherwise, oil production will take place which is not desired for the time being.

A brief description about the utilised distributions:

- *Distribution 1*: Oil lies in the middle of the reservoir and it fades towards the corners of the grid. Oil saturation variations per cell are relatively smooth (**Fig. 4.7**).
- *Distribution 2*: Oil lies in the diagonal that connects the two wells. Variation of oil distribution is the most abrupt of all distributions (**Fig. 4.8**)
- *Distribution 3*: It is a more statistical than real case scenario. It exhibits constant but smooth variations in a random fashion. No geometrical pattern as to where oil is located may be expressed (**Fig. 4.9**).
- *Distribution 4*: It resembles the Distribution 2 case but with smoother variations; oil saturation fades gradually towards the corners of the grid as opposed to the abrupt variation in the second case. Again, it is a statistical rather than a realistic model (**Fig. 4.10**).
- *Distribution 5*: Oil is located at the upper part of the diagonal between the producer and the injector (**Fig. 4.11**).

Although different actual saturation values are used in the various distributions (for the different wettability systems that exhibit different oil residual saturation values), they all generally satisfy the above criteria.

In each time step a number of iterations is performed equal to the product of the number of blocks in the three directions. In the case of a 500x500x1 grid 250.000 iterations need to be solved per time step. Constant saturation per block generally facilitates the convergence of the saturation equation and hence, the pressure equation as well. This is why the number of linear iterations should be probably increased in runs in which saturations vary. Thus, in grids that exhibit abrupt variations a distorted result may appear in comparison with a uniform saturation case.

The tracer response curve differs for various saturation distributions. The maximum concentration value will offset and the curve itself will appear different for the injected tracer that follows different flow paths is in contact with different water (and oil) quantities so that tracers' velocity and retardation vary in a per-block-fashion.

In order to demonstrate that adequately let us consider a 1D grid and two different saturation distributions. A uniform one with constant S_o of 0.25 and a second one where the first half blocks contain only water and the remaining blocks S_o of 0.5. The average oil saturation in the latter is still 0.25. Residual oil saturation is 0.5 so oil is immobile in both cases. Moreover, water relative permeability at S_{OR} is 0.6, at S_w = 1 it is equal to the unity and for S_o = 0.25 it is equal to 0.8. The corresponding tracer concentrations are presented in **Fig. 4.12.**

The concentration curve of the distributed case is slightly shifted to the left hand side. At early times water velocity is greater due to increased oil saturation whereas at late times it is reduced due to reduced oil saturation in comparison with the uniform model. Although, maximum-concentration time is actually the same (at least in this simple example) the curve in the varying-saturation model is more dispersive (the actual peak-concentration absolute value is reduced in comparison with the uniform model).

Water (and subsequently tracer) velocity increases with oil saturation and vice versa so that conservative tracer exhibits higher velocity (and earlier breakthrough) in cases of increased oil saturation. Passive tracer velocity equal to the water one is:

$$u_w = \frac{Q}{A} = \frac{Q^{s.c} * B_w}{L_y L_z \varphi \,(1 - S_o)}$$

Even if the actual velocity cannot be calculated due to varying cross-sectional area, it can be said that for higher residual oil saturation, water velocity will be increased.

Apart from such qualitative criteria saturation distributions were modelled in order to determine their effect on the numerical techniques as well.

The predictions in terms of S_{OR}, swept pore volume through mode time, breakthrough time, $t_{50\%}$ and mean residence time for the various distributions (averaging respectively at S_o= 0.25 and 0.35) are presented in **Tables 4.3- 4.13.** Furthermore, the corresponding tracer responses are depicted in **Fig. 4.13** conservative tracer for S_{OR}=0.35), **Fig. 4.14** (partitioning tracer with K_d= 0.5) and **Fig. 4.15** (partitioning tracer with K_d= 4) for each saturation distribution model. Tracers with partition coefficients (K_d = 1, 1.5, 1.8 and 3) exhibit exactly the same trend but with relative offsets in the time axis. Similar plots are obtained in the case of residual oil saturation of 0.25, with the only difference in the maximum concentration absolute value and water velocity.

Concentration curves of active tracers in Distribution 1 and 2 depart the most from the uniform distribution. Those distributions exhibit the most abrupt saturation variations per block. This effect is heavily pronounced if average reservoir pressure versus time, and oil saturation versus time trends are examined (see **Fig. 4.16** and **Fig. 4.17**).

The crux of the problem lies within the fundamentals of simulation. Since, oil saturation exhibits a residual value it should remain immobile. Hence, reservoir pressure should remain constant over time, for no oil is produced and production rate is exactly equal to the injection rate. When a saturation distribution is implemented non-linearity rises from the very first time step. Mobility ratio depends on saturation. Big variations in saturation values hinder the convergence of the solver (single-phase flow) and locally the model seems to exhibit two-phase flow (pressure drop and oil saturation reduction due to production). Hence, for abrupt saturation alternations (from S_o values of 0.5 to1) two phase flow is simulated (at a small scale though). Since water (or oil) saturation is different for each block, different mobility ratios are used for each pressure equation as well. The latter is not anymore constant over time but indicates variations. The oil saturation reduction and the corresponding pressure drop are rather small however (at the order of E-6). In a larger scale it could cause more severe problems. This is the reason why ***upscaling*** **(**constitutes to the averaging of properties) is performed. Saturation upscaling and not least relative permeability upscaling is vital for reducing numerical errors.

The pressure and saturation equation errors affect the tracer response as well as the latter values are used in the material balance equations (in the *residual term R*) from which concentrations are calculated. This effect can be only realised when tracer concentrations are investigated in conjunction with pressure and saturations trends, whereas in other cases (as it will be shown in Mobile Oil Study) the concentration curve itself may point towards numerical errors.

Concentration curves do not exhibit the normal-distribution-like shape (as in the uniform saturation distribution cases) but are rotated a bit to the left, in terms of the varying saturation models. This indicates the effect of numerical dispersion, which rises in coarse grid blocks (which is not the case here). Time step value has a similar effect though. Since, reservoir size is large (1000x1000x90 ft^3), flowrate was adjusted in order to restrict water velocity below 1 ft/day and given the fact that a maximum number of 1000 time steps can be implemented in Eclipse, the very value of time step had to be increased. Starting from a time step of 2.5 days, the latter is increased for partitioning tracers with higher partition coefficients at 3, 3.5, 5 etc. days. The crux of this issue however is the fact that balance equations of tracers (of linear convection type) are solved fully implicitly. Yet, such an implicit scheme is susceptible to numerical diffusion (*Eclipse Technical Description*) not least in regions where concentrations vary the most; such as the varying saturation distribution models.

Generated curves for various saturation distributions differ from the uniform distributed one. Apart from the mathematical explanation unravelled above, the different flow paths that flow takes place exhibit different saturations and therefore different velocity as well as different relative permeability values per block. In fact water velocity varies per block in the varying saturation model, for each block exhibits different saturation. In addition, partitioning tracers are in contact with varying amount of oil and hence, their partition between the aqueous and oleic phases cannot be easily foreseen. Generally, a delayed active tracer response means that higher oil saturations occur (accompanied by an earlier passive tracer response which points towards the same result).

4.3.3. Oil-Wet and Strongly Oil-Wet Study

In terms of the oil-wet system (S_{OR}= 0.6) the various oil saturation distributions average at 0.25 and 0.4 whereas in the highly oil-wet system (S_{OR}= 0.7) they average at 0.25, 0.4 and 0.5. The reason for generating more saturation distributions (rather than the typical 0.25 S_o value) is to Fig. if there is a particular trend in numerical techniques for different average saturations.

The concentration curves for conservative and partitioning curves (K_d= 0.5, 4) for the oil-wet system (S_O= 0.4) and the highly oil-wet system (S_O= 0.5) for the various saturation distributions are illustrated in **Figs. 4.18-4.23**.

As far as oil-wet model is concerned, the corresponding partition tracers' curves of the varying saturations exhibit higher retardation than the uniform one, due to the fact that locally higher saturations exist that delay the response. This effect can be seen in all partition tracers but it is more prolonged in higher partition coefficient values where the curves are well-distinguished. The same appeals for the highly oil-wet system as well, even more prolonged by virtue of the higher oil saturation.

The conservative tracer fluid-in-place chart for the oil-wet reservoir is presented in **Fig. 4.24**. At day one 1500 barrels of conservative tracer are injected and the reported concentrations are dimensionless. Hence, for totally one day injection period and a flow rate of 1500 stb/d initially (in the injection well block) tracer's dimensionless concentration is 1. However, at the production well during breakthrough time, not a spike of value 1 in terms of tracer concentration is observed (the area of concentration vs time plot is always 1 though, which means that the injected quantity of tracers injected is fully recovered at the production well). From a minimum value concentration constantly increases up to a maximum value, which exhibits a concentration value of E-2. From that point on, concentration constantly decreases up to 0. At day 2 when tracer injection period is finished, at the neighbouring blocks of the injection well, a varying concentration among them may be observed. This is the effect of *dispersion* and *molecular diffusion,* in which the molecules of a substance (in this case tracer) move from areas of high concentration to areas of low concentration *(Bachelor, 1967*). Dispersion denotes the effects of varying velocity (due to pore-size variations velocity at the pore scale exhibits variations as well) and heterogeneities. At the same time a velocity is being given to tracer molecules through injection and production flow rate. The latter denotes the advection term. Tracer concentration is changing in the entire grid due to the combination of all three effects; from higher to lower concentrations (diffusion), due to the possible stream lines that flow takes place and the varying velocity according to the pore size (mechanical dispersion) as well as due to the established flow regime (advection).Furthermore, there is a percentage of error related to the numerical solution (numerical dispersion).

Dispersion is the reason why for higher partition coefficient the maximum concentration is reduced (**Fig. 4.6**). Since oil saturation is constant (it exhibits a residual value) and flow rate is fixed for the various partition coefficient values tracer velocity is the same. For higher k_d the partitioning of the active tracer into the oleic phase is greater leading to increased retardation. Hence, higher amount of time is required for tracer breakthrough, during which dispersion effect is enhanced and the peak-concentration will inevitably exhibit a lower absolute value.

Ostensibly, a very short distance or extremely high velocity would probably diminish the effect of dispersion with spike-type concentration responses (peak concentration close to 1). However, extremely high velocities induce errors again related to dispersion (very high velocity would give a very high Peclet number and therefore, severe dispersion effects). Therefore, the higher the amount of time that a tracer spends within the reservoir the higher the dispersion but simultaneously very high velocities cause also increase of dispersion effects. Hence, the golden ratio to alleviate dispersion is moderate velocities On the contrary, either very low velocity or high enough distance between the injector and the producer would intensify the effect of molecular diffusion.

The corresponding partitioning tracer concentration for $k_d = 1.8$ (**Fig. 4.25**), exhibits the same trend, yet more delayed over time. The numerical results in terms of the oil-wet case for different initial saturations and for various distributions are presented in **Tables 4.14-4.24.** The corresponding results with regards to the strongly oil-wet cases are illustrated in **Tables 4.25-4.40**.

4.4. Numerical Techniques Discussion

In terms of mode time and $t_{50\%}$ the more abrupt the saturation variation is the worst the predictions are. In the mixed-wet study case, Distribution 2 model – that exhibits the most abrupt saturation variations - yields the most inaccurate results. In other studies however such as the oil-wet one fairly accurate predictions are obtained through Distribution 2. This is due to the fact that in terms of the various wettability systems not exactly the same saturation values are used per block in order to utilise the full range of oil saturations that exhibit zero relative permeability value. All saturation distributions are listed in **APPENDIX.** Hence, as far as oil-wet system is concerned the total number of blocks containing oil (averaging at 0.25 and 0.35 S_o, respectively) are greater than the mixed-wet system. The same appeals if oil-wet system is compared with the strongly oil-wet one.

If the oil-containing blocks orientation is towards the diagonal that connects production and injection well this is advantageous for the aforementioned techniques. Also, when a stronger oil-wet system is analysed (residual oil saturation value is greater) and the two extreme oil and water saturation values are utilised ($S_o = S_{or}$ and $S_w = 1$) in order to set the average oil saturation at a given value (either 0.25 or 0.35 or 0.4 or 0.5) in total, an increased number of oil-containing cells will be eventually used. Hence, the total number of flow paths in oil regions is higher than the corresponding flow paths in water regions, so that higher water velocity is attained (earlier passive tracer breakthrough) and greater partitioning tracer retardations by virtue of the locally increased oil saturation. Therefore, higher residual oil saturation will be obtained by virtue of the latter.

For the various wettability systems (different residual oil saturations) if a 0.25 uniform oil saturation is implemented, almost identical predictions are obtained as far as S_o is concerned. Similarly, if the same saturation distributions that were used in the mixed-wet study are implemented in studies with enhanced residual oil saturations (oil-wet and strongly oi-wet) again almost identical results will be obtained. Those minor variations are related to relative permeability differences among the various wettability systems. This is the very reason why not the same actual distributions were performed but they were modified ad hoc for the various residual saturation values.

It can be observed as a pattern in the uniform saturation distributions that the higher the residual oil saturation the more accurate the predictions are. The latter, in conjunction with a facilitating in terms of flow distribution (greater number of oil-containing blocks in the main diagonal) may lead to excellent predictions.

Naturally, results obtained through the usage of breakthrough times exhibit the highest variations. They exhibit the same tendency as mode time (earlier conservative tracer breakthrough for higher oil saturation as well as delayed partitioning tracer breakthrough) but they are highly prone to numerical dispersion.

The utilisation of Mean Residence Time is beneficial to eliminate those effects. While mode time, $t_{50\%}$ and breakthrough time are very sensitive towards saturation alternations, infinitesimal variations are observed in predictions with regards to Mean Residence Time. In the latter, area rather than the x-coordinate (time) than corresponds to a certain y-coordinate (concentration) is sought, rendering its predictions unaffected by offsets along the time axis. While variations of the order of 10% may be observed through the utilisation of mode time for a different saturation distributions, in case of residence time those variations are rather small. However, it is the most expensive method with regards to both computational time but most importantly experimental time, particularly when higher partition coefficients are used.

In order to restrict the quota of extrapolation an increased time step (18 days) was performed. For small partition coefficient values such time step is sufficient to avoid any extrapolation calculations. For greater partition coefficients (K_d= 3 or 4) great dependency upon extrapolation occurs. Especially for higher residual oil saturation runs (strongly oil-wet) this dependency increases. This is why in the cases of K_d= 3 or 4 increased alternations rise, in comparison with lower partition coefficients. The time step was not increased (in order to reduce the extrapolation effect) in order to illustrate the variations that may obtained in terms of S_o and swept pore volume predictions.

Regarding mode time implementation, a passive along with a partitioning tracer were used. Starting with a time step of 2.5 days, the latter was increased in active tracers with larger partition coefficients. Yet, in that case the non-partitioning tracer time (mode or $t_{50\%}$) was recalculated for the greater time step. This was conducted due to the fact that diffusion apart from sharpening or broadening exhibits a leftwards rotation, as descripted previously. Hence, mode-time of a conservative tracer obtained through a smaller time step coupled with a mode-time of an active tracer where a larger time step was performed would generate abnormal results due to the shape of diffusion.

It can be inferred that actually fewer partitioning tracers may be used for the differences in the predictions among them are small. Some more pronounced variations like in the case of $t_{50\%}$ are due to the increased time step being used for higher partition coefficients. The implemented interpolation to determine that specific time value is less accurate for a very high simulation time step.

4.5. ECLIPSE vs UTCHEM comparison

After the comparison of the two simulators in a 1D model, they were also tested for a Residual Oil 2D case. The grid that was descripted above and comprises 500.000 blocks, could not be used in UTCHEM. Initialisation fails from the very first time step due to the increased number of grid blocks and subsequently the number of equations that are solved at each time step.

Hence, a different grid was implemented in both simulators with the same properties as before. The only thing that had to be modified is the relative permeability versus saturation matrices of oil and water. Although in ECLIPSE there is no restriction in relative permeability input, in terms of UTCHEM a certain model needs to be given. A straight-line (exponent n= 1) Corey type of relative permeability was selected (**Fig. 4.26**). The grid, reservoir and well properties are presented in **Table 4.40**.

Grid blocks' increased size enhances the effect of numerical dispersion, so that the selected block size is anything but the optimal one. Still, the comparison for a given grid between the two simulators is valid.

Two saturation distributions were modelled similar to the ones above (Distribution 2.1 is identical to Distribution 2 and Distribution 2.2 identical to Distribution 5). Additionally, a completely random distribution (Distribution 2.3) was selected with no particular physical meaning (its values can be seen in APPENDIX in both codes of ECLIPSE and UTCHEM). It is however a measure of the solvers' ability.

One passive and four partitioning tracers (k_d= 0.5, 1, 1.5, 2) were used and numerically the results were compared through the utilisation of peak-concentration time. The generated conservative and partitioning tracer (K_d= 1) for the various distributions are illustrated in **Figs. 4.27- 4.34**.

The S_o predictions from mode time utilisation are presented in **Tables 4.41- 4.44**. In terms of the 1D model, the concentration curves were compared to the analytical solution. In the 2D model however, the analytical solution cannot be applied for neither velocity nor total length are known. The generated responses can be compared vicariously through the use of a numerical method. By utilising peak-concentration times for the various distributions it can be seen that UTCHEM provides more accurate tracer responses than ECLIPSE.

Regarding the uniform distribution through UTCHEM the S_{or} prediction is much more precise than the ECLIPSE one. The same occurs for the other distributions, save the random one. In the latter, ECLIPSE manages to outperform UTCHEM due to its more powerful solver. As said before, UTCHEM exhibits limitations in the number of maximum grid blocks that can be used. Moreover, for saturation variation per block, data obtained from ECLIPSE are more reliable. In ECLIPSE the total number of linear and non-linear equations can be controlled by the user. Such a saturation variation causes non-linearity which can be addressed by the user. In this case the limitations of UTCHEM with regards to real-field dimensions and data are apparent.

On the other hand, the tracer mass balance equation used in UTCHEM is more accurate than the ECLIPSE one. This stems from the higher order scheme being used in the former compared to the second order one of ECLIPSE. In a field-scale problem UTCHEM could not have been the primary black-oil simulator. However, with regards to chemical compounds studies such as tracers, alkaline-polymer- surfactant flooding it may provide useful insight as it is meant to simulate such reactions.

Figures of chapter 4

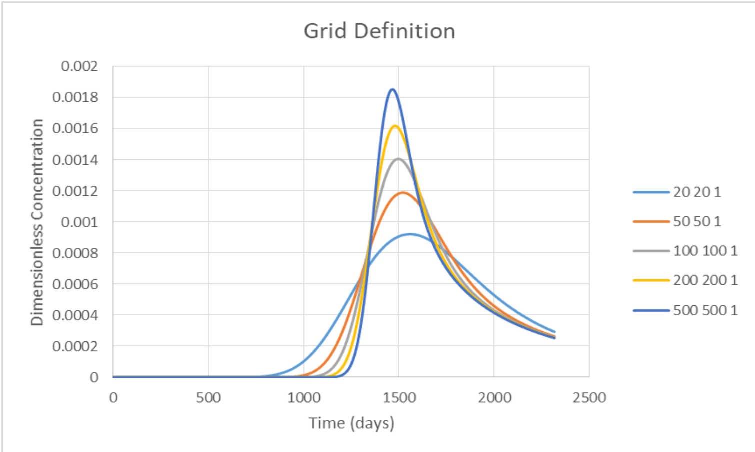

Figure 4.1: Procedure for identifying the optimum grid size.

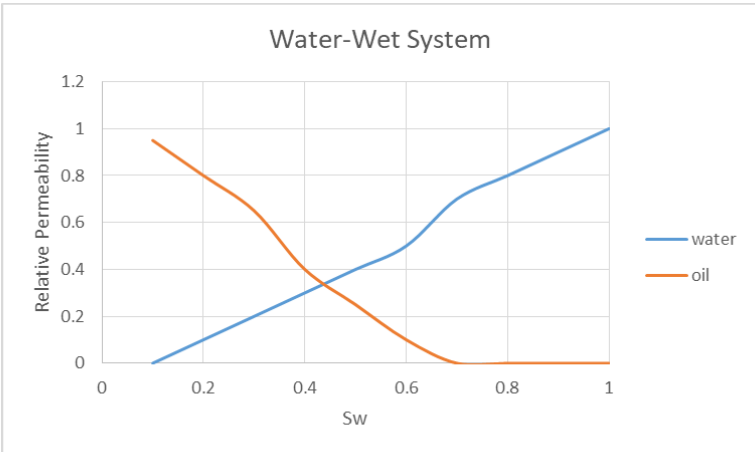

Figure 4.2: Relative permeability system for the water-wet system.

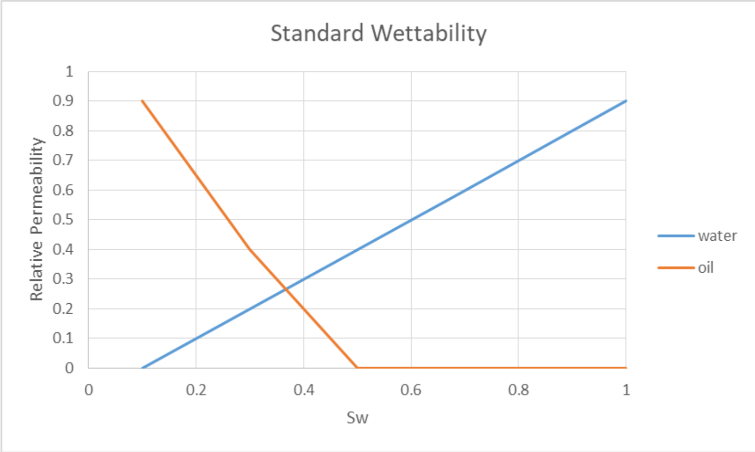

Figure 4.3: Relative permeability system for the neutral-wet system.

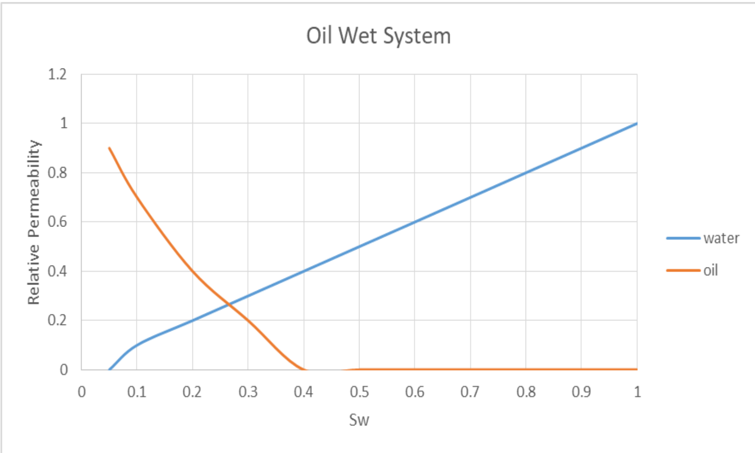

Figure 4.4: Relative permeability system for the oil-wet system.

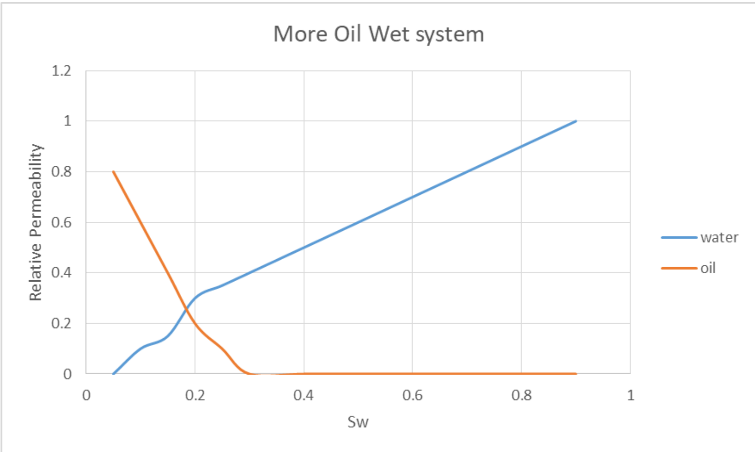

Figure 4.5: Relative permeability system for the highly oil-wet system.

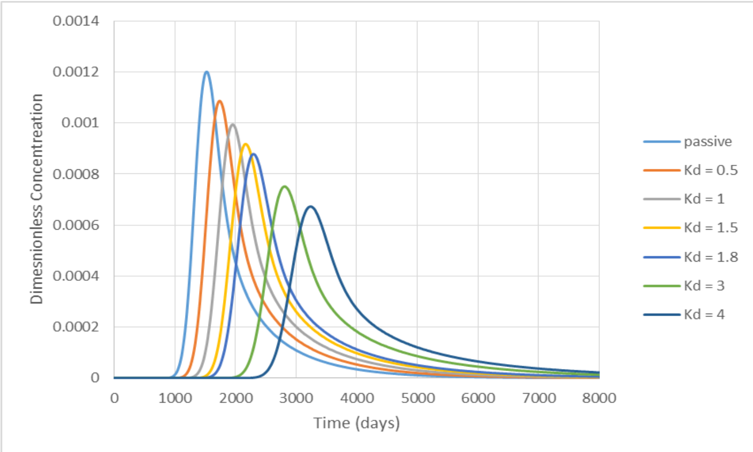

Figure 4.6: Tracer response for various partitions coefficients in the water-wet system for $S_{OR} = 0.25$.

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1	1	1	1	1	1	1	1	1	1
0.9	0.9	0.9	0.9	0.8	0.8	0.9	0.9	0.9	0.9
0.8	0.8	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.9
0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.8
0.7	0.7	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.7
0.7	0.7	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.7
0.7	0.7	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.7
0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.8
0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7
0.8	0.9	1	1	1	1	1	1	1	1

Figure 4.7: Water saturation (S_w) distribution of ‘Distribution 1’ model.

0.5	0.5	0.5	0.5	0.5	1	1	1	1	1
0.5	0.5	0.5	0.5	0.5	1	1	1	1	1
0.5	0.5	0.5	0.5	0.5	1	1	1	1	1
0.5	0.5	0.5	0.5	0.5	1	1	1	1	1
0.5	0.5	0.5	0.5	0.5	1	1	1	1	1
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5

Figure 4.8: Water saturation (S_w) distribution of ‘Distribution 2’ model.

0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8
0.8	0.7	0.7	0.7	0.6	0.6	0.7	0.7	0.8	0.7
0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.6	0.6	0.6
0.6	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7
0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.8
0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.8	0.8
0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Figure 4.9: Water saturation (S_w) distribution of ‘Distribution 3’ model.

0.5	0.6	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9
0.7	0.5	0.6	0.7	0.8	0.9	0.9	0.9	0.9	0.9
0.7	0.6	0.5	0.5	0.6	0.8	0.9	0.9	0.9	0.9
0.8	0.7	0.6	0.5	0.5	0.6	0.8	0.9	0.9	0.9
0.9	0.8	0.7	0.5	0.5	0.5	0.6	0.8	0.9	0.9
0.9	0.9	0.8	0.6	0.5	0.5	0.5	0.7	0.8	0.9
0.9	0.9	0.9	0.8	0.6	0.5	0.5	0.6	0.7	0.9
0.9	0.9	0.9	0.9	0.8	0.7	0.5	0.5	0.6	0.7
0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.6	0.5	0.7
0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.6	0.5

Figure 4.10: Water saturation (S_w) distribution of 'Distribution 4' model.

1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	1	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	1	1	1	0.5	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	1	1	0.5	0.5	0.5
1	1	1	1	1	1	1	1	0.5	0.5
1	1	1	1	1	1	1	1	1	0.5
1	1	1	1	1	1	1	1	1	1

Figure 4.11: Water saturation (S_w) distribution of 'Distribution 5' model.

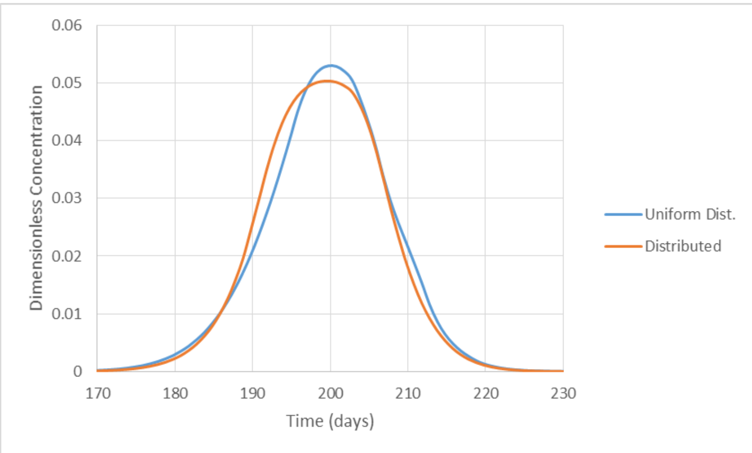

Figure 4.12: Conservative tracers' response for a uniform and a varying S_o in a 1D grid.

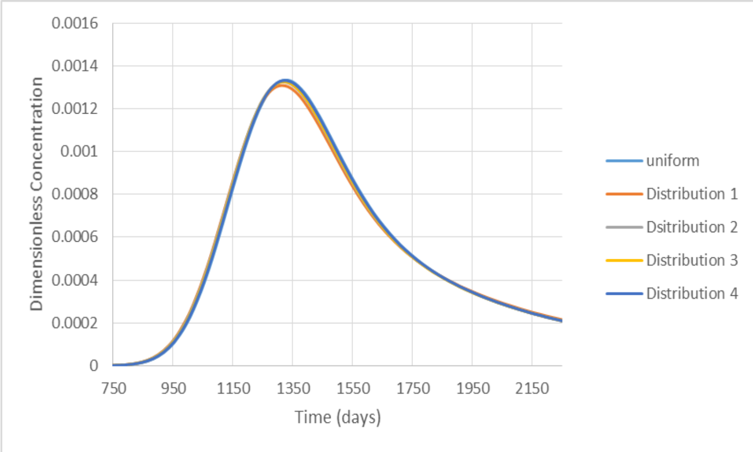

Figure 4.13: Conservative tracer response for different saturation distributions.

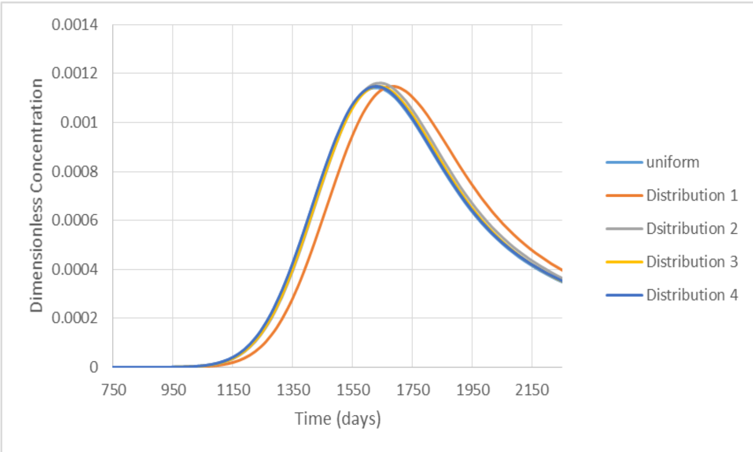

Figure 4.14: Partitioning tracer response (K_d= 0.5) for different saturation distributions.

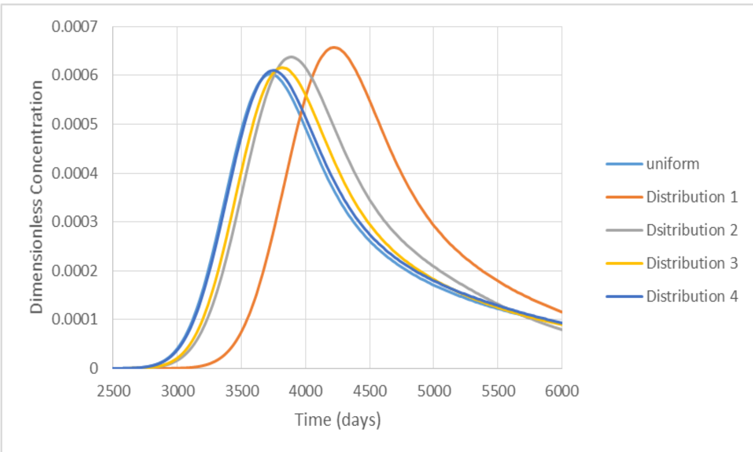

Figure 4.15: Partitioning tracer response (K_d= 4) for different saturation distributions.

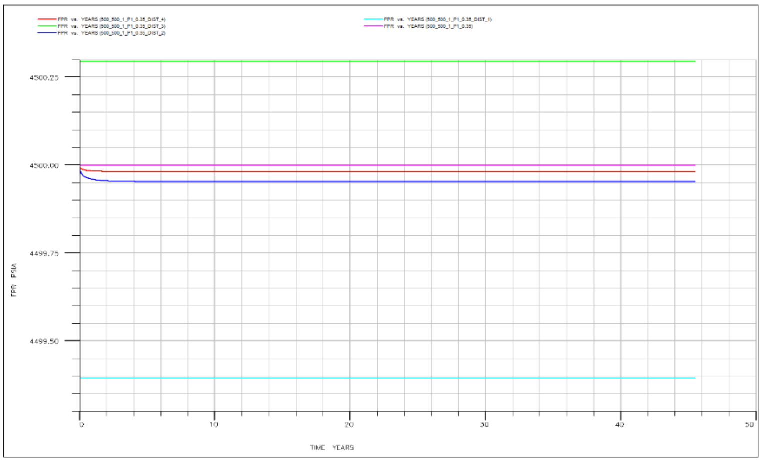

Figure 4.16: Average Reservoir Pressure for different saturation distributions (S_{OR} = 0.35).

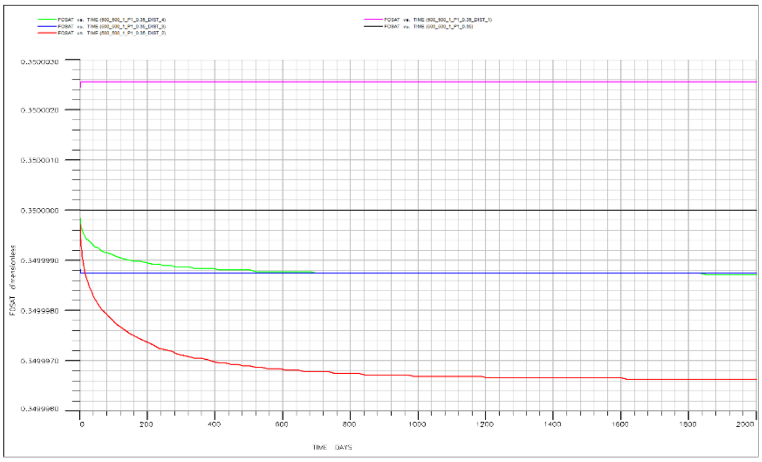

Figure 4.17: Oil saturation vs pressure for different saturation distributions.

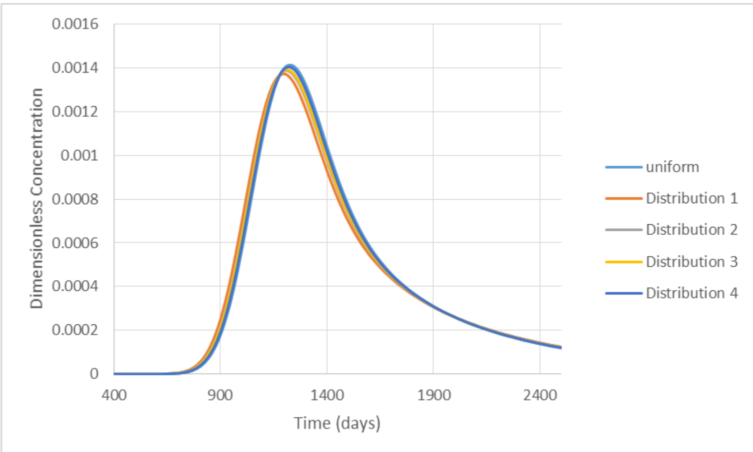

Figure 4.18: Conservative tracer response for different saturation distributions in the oil-wet study (S_O= 0.4).

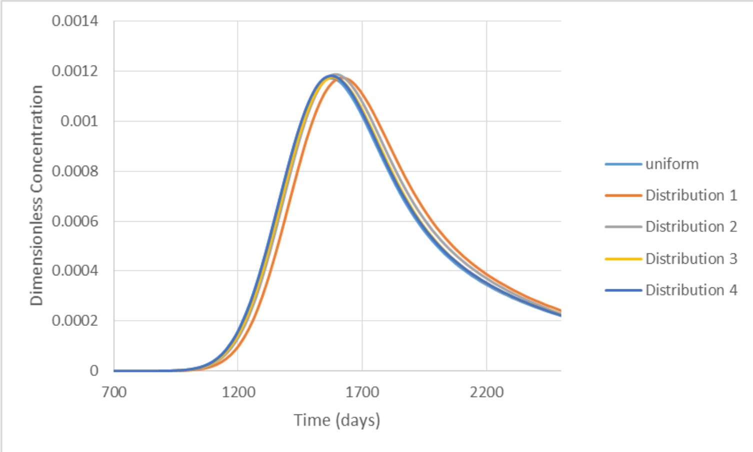

Figure 4.19: Partitioning tracer response (K_d= 0.5) for different saturation distributions in the oil-wet study (S_O= 0.4).

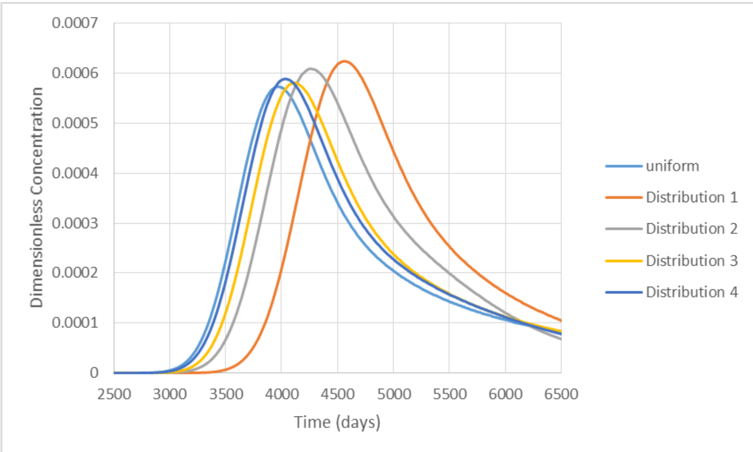

Figure 4.20: Partitioning tracer response (K_d= 4) for different saturation distributions in the oil-wet study (S_O= 0.4).

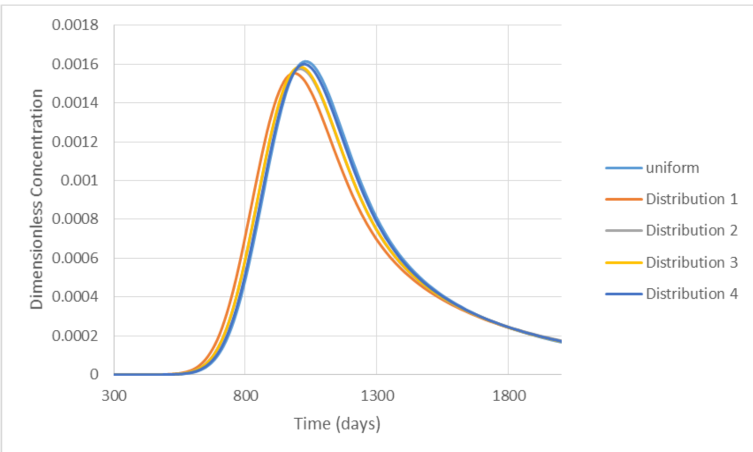

Figure 4.21*:* Conservative tracer response for different saturation distributions in the strongly oil-wet study (S_O= 0.5).

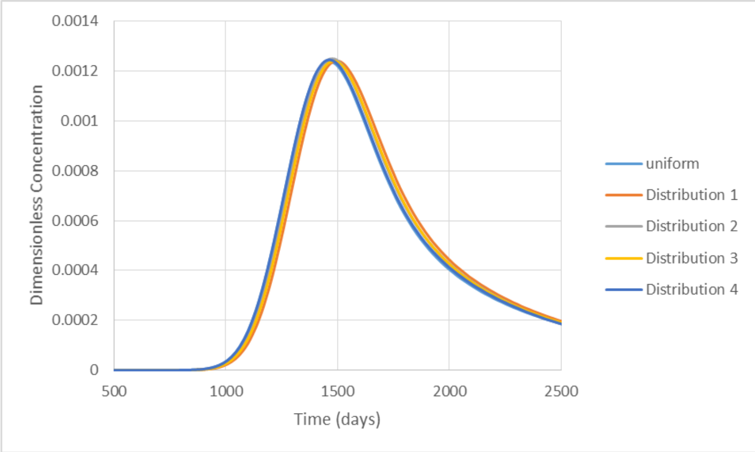

Figure 4.22: Partitioning tracer response (K_d= 0.5) for different saturation distributions in the strongly oil-wet study (S_O= 0.5).

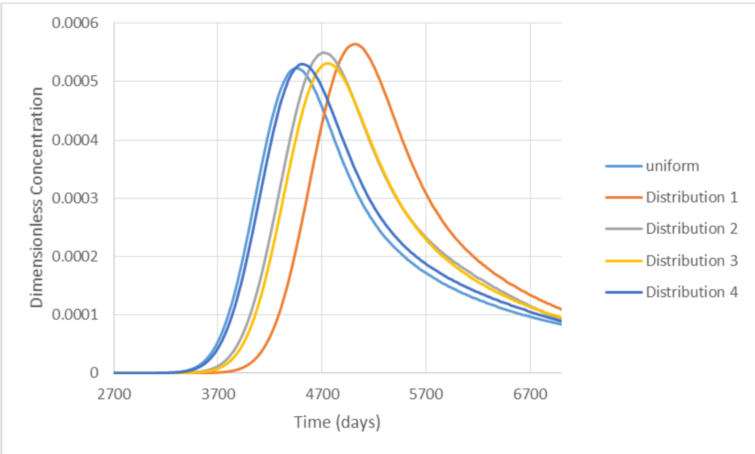

Figure 4.23: Partitioning tracer response (K_d= 4) for different saturation distributions in the strongly oil-wet study (S_O= 0.5).

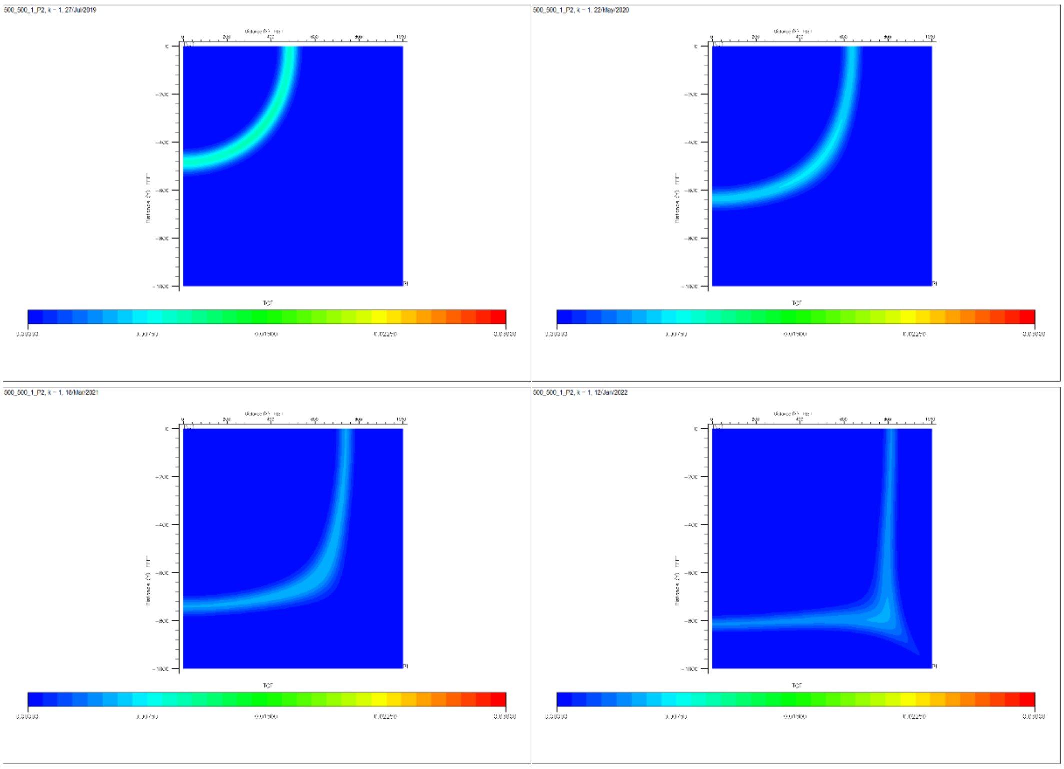

Figure 4.24: Conservative tracer concentration over time chart.

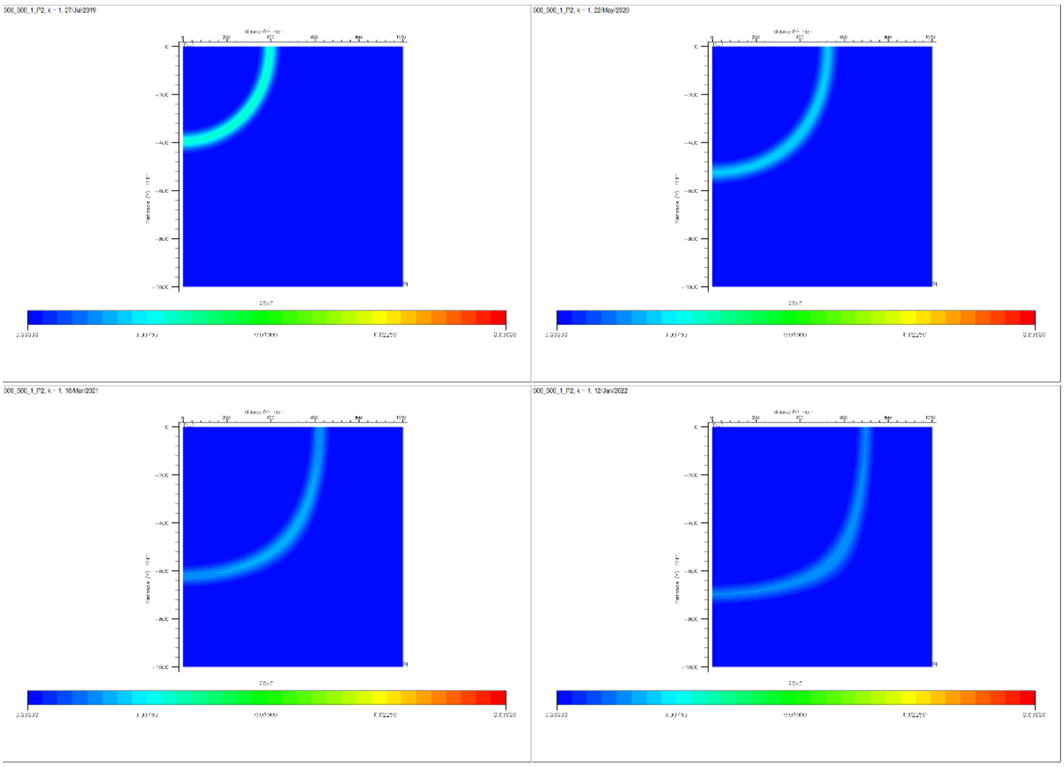

Figure 4.25: Partitioning tracer (k_d= 1.8) concentration over time chart.

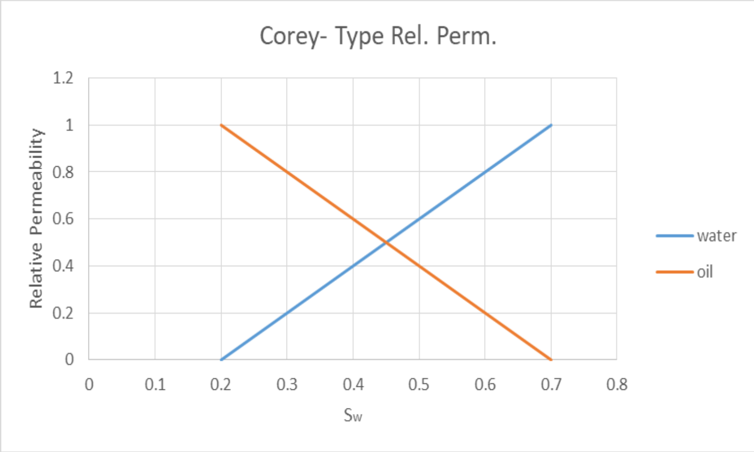

Figure 4.26: Pseudo- Corey relative permeability curves.

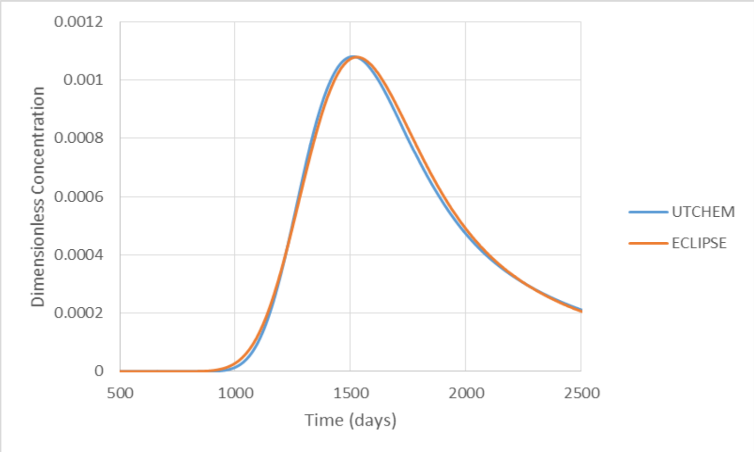

Figure 4.27: Conservative tracer response in the uniform distribution case.

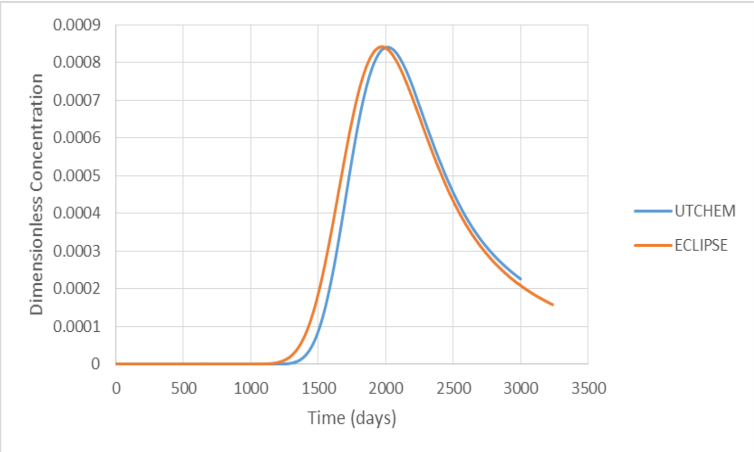

Figure 4.28: Partitioning tracer response (k_d= 1) in the uniform distribution case.

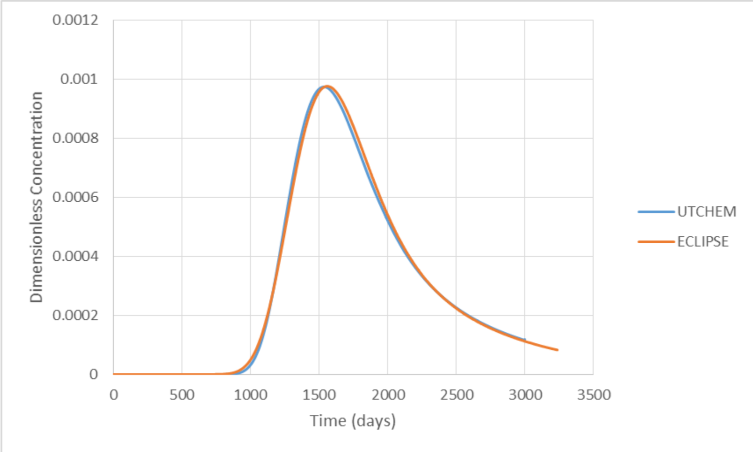

Figure 4.29: Conservative tracer response in the case of Distribution 2.1.

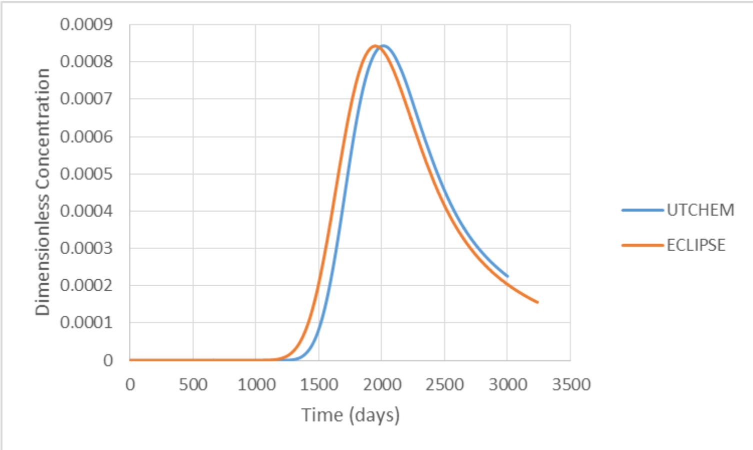

Figure 4.30: Partitioning tracer response (k_d= 1) in the case of Distribution 2.1.

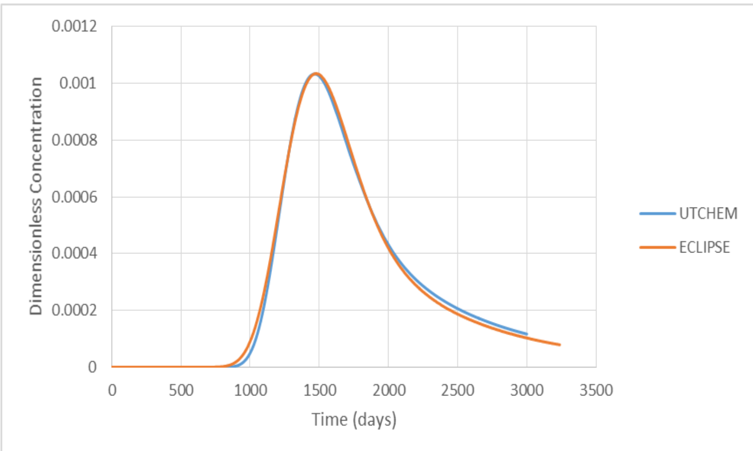

Figure 4.31: Conservative tracer response in the case of Distribution 2.2.

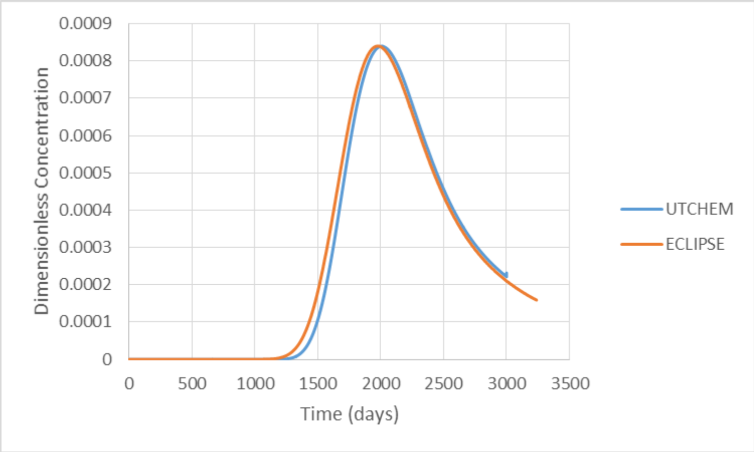

Figure 4.32: Partitioning tracer response (k_d= 1) in the case of Distribution 2.2.

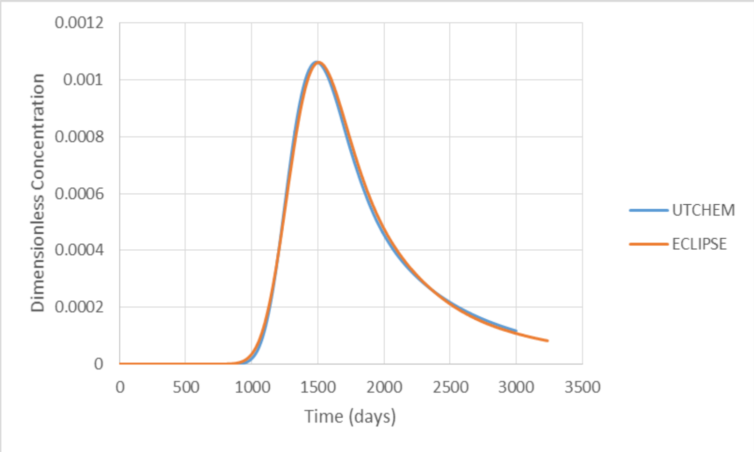

Figure 4.33: Conservative tracer response in the case of Distribution 2.3.

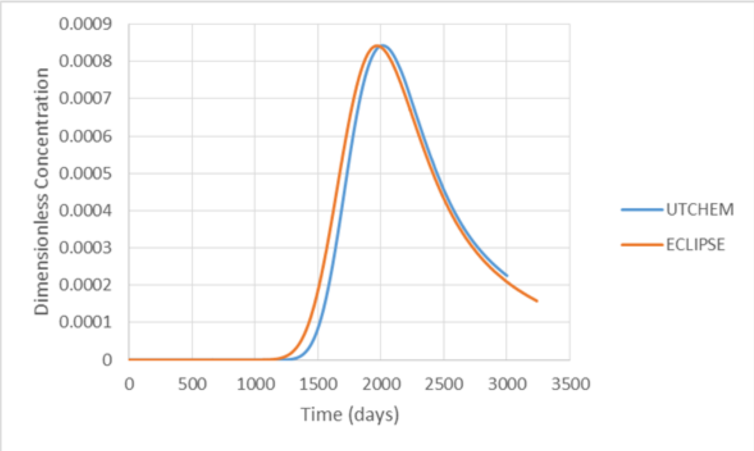

Figure 4.34: Partitioning tracer response (k_d= 1) in the case of Distribution 2.3.

Tables of chapter 4

Water-Wet Uniform Dist. (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1467.78	1679.03	0.5	**0.2235**	3.86	10.60
1467.78	1890.28	1	**0.2235**	3.86	10.60
1467.78	2101.53	1.5	**0.2235**	0.82	10.60
1467.78	2229.03	1.8	**0.2237**	0.69	10.53
1480.28	2752.78	3	**0.2227**	0.44	10.91
1480.28	3177.78	4	**0.2228**	0.35	10.88

Water-Wet Uniform Dist. (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1676.29	1919.96	0.5	**0.2252**	9.90
1676.29	2163.63	1	**0.2252**	9.90
1676.29	2414.25	1.5	**0.2269**	9.24
1676.29	2560.42	1.8	**0.2266**	9.35
1676.29	3145.15	3	**0.2261**	9.58
1676.29	3177.78	4	**0.2259**	9.66

Water-Wet Uniform Dist. (S_{OR}= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.92	2269.93	**0.2245**	10.20	21966446	0.976	1.14
1	1982.92	2557.26	**0.2246**	10.16	21969307	0.976	1.29
1.5	1982.92	2845.52	**0.2248**	10.08	21975543	0.977	1.44
1.8	1982.92	3019.53	**0.2251**	9.98	21982641	0.977	1.52
3	1982.92	3738.91	**0.2279**	8.84	22063714	0.981	1.89
4	1982.92	4403.32	**0.2338**	6.48	22233564	0.988	2.22

Water-Wet Uniform Dist. (S_{OR}=0.25)				
k_d	T_{bt} cons.	part.	So	Deviation (%)
0.5	812.78	955.28	**0.2596**	3.85
1	812.78	1100.28	**0.2613**	4.52
1.5	812.78	1245.28	**0.2619**	4.74
1.8	812.78	1332.78	**0.2622**	4.89
3	672.78	1507.78	**0.2926**	17.06
4	672.78	1797.78	**0.2948**	17.92

Table 4.1: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the water-wet system (S_{OR}= 0.25).

Water-Wet Uniform Dist. (S_{OR}= 0.3)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1370.28	1624.03	0.5	**0.2703**	3.09	9.91
1370.28	1877.78	1	**0.2703**	0.95	9.91
1370.28	2131.53	1.5	**0.2703**	0.66	9.91
1370.28	2285.28	1.8	**0.2706**	0.56	9.80
1382.78	2912.78	3	**0.2694**	0.36	10.19
1382.78	3420.28	4	**0.2692**	0.29	10.27

Water-Wet Uniform Dist. (S_{OR}= 0.3)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1565.08	1857.46	0.5	**0.2720**	9.33
1565.08	2149.87	1	**0.2720**	9.33
1565.08	2449.19	1.5	**0.2736**	8.81
1565.08	2624.59	1.8	**0.2733**	8.90
1565.08	3326.26	3	**0.2728**	9.07
1565.08	3911.00	4	**0.2726**	9.14

Water-Wet Uniform Dist. (S_{OR}=0.3)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1851.99	2196.34	**0.2711**	9.64	21827001	0.970	1.19
1	1851.99	2540.99	**0.2712**	9.61	21829538	0.970	1.37
1.5	1851.99	2886.95	**0.2714**	9.52	21837891	0.971	1.56
1.8	1851.99	3096.31	**0.2718**	9.40	21849174	0.971	1.67
3	1851.99	3977.17	**0.2767**	7.77	21996103	0.978	2.15
4	1851.99	4833.05	**0.2869**	4.35	22312874	0.992	2.61

Water-Wet Uniform Dist. (S_{OR}=0.3)				
k_d	T_{bt} cons.	part.	So	Deviation (%)
0.5	747.78	917.78	**0.3126**	4.19
1	747.78	1090.28	**0.3141**	4.71
1.5	747.78	1265.28	**0.3157**	5.24
1.8	747.78	1370.28	**0.3162**	5.41
3	612.78	1617.78	**0.3535**	17.82
4	612.78	1962.78	**0.3552**	18.39

Table 4.2: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the water-wet system (S_{OR}= 0.3).

Mixed-Wet Uniform Dist. (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1467.78	1678.50	0.5	**0.2231**	3.88	10.77
1467.78	1890.28	1	**0.2235**	1.20	10.60
1467.78	2101.53	1.5	**0.2235**	0.82	10.60
1467.78	2229.03	1.8	**0.2237**	0.69	10.53
1480.28	2752.78	3	**0.2227**	0.44	10.91
1480.28	3177.78	4	**0.2228**	0.35	10.88

Mixed-Wet Uniform Dist. (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1676.27	1919.89	0.5	**0.2252**	9.90
1676.27	2163.57	1	**0.2252**	9.90
1676.27	2414.24	1.5	**0.2269**	9.24
1676.27	2560.41	1.8	**0.2266**	9.35
1676.27	3145.12	3	**0.2261**	9.58
1676.27	3632.45	4	**0.2259**	9.66

Mixed-Wet Dist. 1 (S_{OR}=0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.89	2269.84	**0.2245**	10.22	21965201	0.976	1.14
1	1982.89	2556.79	**0.2245**	10.22	21965217	0.976	1.29
1.5	1982.89	2843.66	**0.2244**	10.22	21964837	0.976	1.43
1.8	1982.89	3015.77	**0.2244**	10.23	21964593	0.976	1.52
3	1982.89	3704.35	**0.2244**	10.23	21964579	0.976	1.87
4	1982.89	4278.24	**0.2244**	10.22	21964755	0.976	2.16

Mixed-Wet Uniform Dist. (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1676.27	1919.89	0.5	**0.2252**	9.90
1676.27	2163.57	1	**0.2252**	9.90
1676.27	2414.24	1.5	**0.2269**	9.24
1676.27	2560.41	1.8	**0.2266**	9.35
1676.27	3145.12	3	**0.2261**	9.58
1676.27	3632.45	4	**0.2259**	9.66

Table 4.3: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform mixed-wet system (S_{OR}= 0.25).

Mixed-Wet Dist. 1 (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1444.03	1731.53	0.5	**0.2848**	2.70	13.92
1444.03	2017.78	1	**0.2843**	0.83	13.74
1444.03	2304.03	1.5	**0.2842**	0.57	13.68
1457.78	2490.28	1.8	**0.2824**	0.49	12.95
1457.78	3175.28	3	**0.2820**	1.32	12.79
1457.78	3740.28	4	**0.2813**	1.12	12.53

Mixed-Wet Dist. 1 (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1673.27	1963.91	0.5	**0.2578**	3.13
1673.27	2254.50	1	**0.2578**	3.12
1673.27	2553.50	1.5	**0.2596**	3.86
1673.27	2727.97	1.8	**0.2594**	3.74
1673.27	3424.13	3	**0.2586**	3.44
1673.27	4002.30	4	**0.2581**	3.26

Mixed-Wet Dist. 1 (S_{OR}= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.89	2269.84	**0.2245**	10.22	21965201	0.976	1.14
1	1982.89	2556.79	**0.2245**	10.22	21965217	0.976	1.29
1.5	1982.89	2843.66	**0.2244**	10.22	21964837	0.976	1.43
1.8	1982.89	3015.77	**0.2244**	10.23	21964593	0.976	1.52
3	1982.89	3704.35	**0.2244**	10.23	21964579	0.976	1.87
4	1982.89	4278.24	**0.2244**	10.22	21964755	0.976	2.16

Mixed-Wet Dist. 1 (S_{OR}= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	800.28	992.78	**0.3248**	29.93
1	800.28	1182.78	**0.3234**	29.36
1.5	800.28	1372.78	**0.3229**	29.17
1.8	800.28	1485.28	**0.3223**	28.91
3	662.78	1757.78	**0.3551**	42.05
4	662.78	2122.78	**0.3551**	42.05

Table 4.4: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.25, Distribution 1).

Mixed-Wet Dist. 2 (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1472.78	1662.78	0.5	**0.2051**	4.36	17.96
1472.78	1852.78	1	**0.2051**	1.35	17.96
1472.78	2044.03	1.5	**0.2055**	0.92	17.82
1472.78	2159.03	1.8	**0.2056**	0.78	17.75
1472.78	2632.78	3	**0.2079**	0.49	18.34
1472.78	3020.28	4	**0.2080**	0.39	18.09

Mixed-Wet Dist. 2 (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1675.45	1899.17	0.5	**0.2108**	15.69
1675.45	2123.25	1	**0.2109**	15.64
1675.45	2345.91	1.5	**0.2106**	15.76
1675.45	2354.37	1.8	**0.1838**	26.50
1675.45	3027.96	3	**0.2120**	15.19
1675.45	3477.46	4	**0.2119**	15.24

Mixed-Wet Dist. 2 (S_{OR}= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.91	2271.54	**0.2255**	9.81	21994246	0.978	1.15
1	1982.91	2575.56	**0.2301**	7.96	22126514	0.983	1.30
1.5	1982.91	2932.26	**0.2420**	3.22	22472312	0.999	1.48
1.8	1982.91	3178.47	**0.2509**	0.37	22741190	1.011	1.60
3	1982.91	4573.61	**0.3034**	21.35	24453965	1.087	2.31
4	1982.91	6131.37	**0.3434**	37.36	25944899	1.153	3.09

Mixed-Wet Dist. 2 (S_{OR}= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	810.28	942.78	**0.2464**	1.42
1	810.28	1067.78	**0.2412**	3.54
1.5	810.28	1187.78	**0.2370**	5.21
1.8	810.28	1257.78	**0.2348**	6.09
3	672.78	1367.78	**0.2561**	2.46
4	672.78	1577.78	**0.2517**	0.66

Table 4.5: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.25, Distribution 2).

Mixed-Wet Dist. 3 (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1454.03	1712.78	0.5	**0.2625**	3.06	4.99
1454.03	1967.78	1	**0.2611**	0.95	4.43
1454.03	2225.28	1.5	**0.2612**	0.65	4.49
1467.78	2387.78	1.8	**0.2583**	0.56	3.31
1467.78	2985.28	3	**0.2563**	0.36	2.52
1467.78	3480.28	4	**0.2553**	0.29	2.11

Mixed-Wet Dist. 3 (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1674.82	1950.39	0.5	**0.2476**	0.96
1674.82	2225.31	1	**0.2474**	1.05
1674.82	2507.01	1.5	**0.2488**	0.47
1674.82	2671.31	1.8	**0.2484**	0.63
1674.82	3326.14	3	**0.2474**	1.06
1674.82	3869.49	4	**0.2468**	1.30

Mixed-Wet Dist. 3 (S_{OR}= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.93	2269.87	**0.2244**	10.22	21965406	0.976	1.14
1	1982.93	2556.76	**0.2244**	10.23	21965011	0.976	1.29
1.5	1982.93	2843.80	**0.2245**	10.22	21965745	0.976	1.43
1.8	1982.93	3016.04	**0.2245**	10.21	21966044	0.976	1.52
3	1982.93	3705.46	**0.2245**	10.18	21967998	0.976	1.87
4	1982.93	4281.60	**0.2247**	10.12	21972222	0.977	2.16

Mixed-Wet Dist. 3 (S_{OR}= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	805.28	977.78	**0.2999**	19.97
1	805.28	1150.28	**0.2999**	19.97
1.5	805.28	1317.78	**0.2979**	19.16
1.8	805.28	1420.28	**0.2979**	19.16
3	667.78	1642.78	**0.3274**	30.95
4	667.78	1967.78	**0.3274**	30.95

Table 4.6: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.25, Distribution 3).

Mixed-Wet Dist. 4 (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1460.28	1679.03	0.5	**0.2305**	3.71	7.79
1460.28	1897.78	1	**0.2305**	1.15	7.79
1460.28	2117.78	1.5	**0.2309**	0.79	7.65
1460.28	2247.78	1.8	**0.2305**	0.67	7.79
1472.78	2792.78	3	**0.2300**	0.42	7.99
1472.78	3230.28	4	**0.2298**	0.33	8.09

Mixed-Wet Dist. 4 (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1673.06	1917.70	0.5	**0.2263**	9.49
1673.06	2162.45	1	**0.2263**	9.47
1673.06	2414.53	1.5	**0.2281**	8.77
1673.06	2561.48	1.8	**0.2278**	8.88
1673.06	3149.63	3	**0.2273**	9.07
1673.06	3639.84	4	**0.2271**	9.15

Mixed-Wet Dist. 4 (S_{OR}= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.96	2271.34	**0.2253**	9.87	21990463	0.977	1.15
1	1982.96	2571.37	**0.2288**	8.47	22090538	0.982	1.30
1.5	1982.96	2904.55	**0.2365**	5.38	22313735	0.992	1.46
1.8	1982.96	3140.83	**0.2449**	2.02	22561733	1.003	1.58
3	1982.96	4250.36	**0.2760**	10.39	23528518	1.046	2.14
4	1982.96	5378.59	**0.2998**	19.91	24328405	1.081	2.71

Mixed-Wet Dist. 4 (S_{OR}= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	805.28	955.28	**0.2714**	8.57
1	805.28	1100.28	**0.2681**	7.25
1.5	805.28	1245.28	**0.2670**	6.80
1.8	805.28	1330.28	**0.2659**	6.36
3	667.78	1502.78	**0.2942**	17.67
4	667.78	1777.78	**0.2936**	17.43

Table 4.7: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.25, Distribution 4).

Mixed-Wet Dist. 5 (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1460.28	1682.78	0.5	**0.2336**	3.64	6.58
1460.28	1901.53	1	**0.2320**	1.14	7.18
1460.28	2117.78	1.5	**0.2309**	0.79	7.65
1460.28	2246.53	1.8	**0.2303**	0.67	7.90
1472.78	2770.28	3	**0.2270**	0.43	9.20
1472.78	3190.28	4	**0.2257**	0.34	9.71

Mixed-Wet Dist. 5 (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1673.62	1925.02	0.5	**0.2310**	7.59
1673.62	2170.32	1	**0.2289**	8.46
1673.62	2418.50	1.5	**0.2288**	8.47
1673.62	2561.57	1.8	**0.2277**	8.94
1673.62	3585.41	3	**0.2758**	10.31
1673.62	4041.03	4	**0.2612**	4.50

Mixed-Wet Dist. 5 (S_{OR}= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.97	2269.81	**0.2244**	10.25	21963993	0.976	1.14
1	1982.97	2556.73	**0.2244**	10.24	21964718	0.976	1.29
1.5	1982.97	2843.70	**0.2244**	10.23	21965221	0.976	1.43
1.8	1982.97	3015.88	**0.2244**	10.23	21965394	0.976	1.52
3	1982.97	3712.42	**0.2252**	9.91	21988120	0.977	1.87
4	1982.97	4284.99	**0.2249**	10.02	21979718	0.977	2.16

Mixed-Wet Dist. 5 (S_{OR}= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	802.78	957.78	**0.2786**	11.43
1	802.78	1102.78	**0.2720**	8.82
1.5	802.78	1240.28	**0.2665**	6.60
1.8	802.78	1317.78	**0.2628**	5.10
3	667.78	1457.78	**0.2828**	13.13
4	667.78	1697.78	**0.2783**	11.32

Table 4.8: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.25, Distribution 5).

Mixed-Wet Uniform Dist. (S_{OR}= 0.35)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1272.78	1570.28	0.5	**0.3186**	2.53	8.98
1272.78	1866.53	1	**0.3181**	0.77	9.11
1272.78	2162.78	1.5	**0.3180**	0.54	9.16
1272.78	2355.28	1.8	**0.3209**	0.45	8.32
1272.78	3067.78	3	**0.3198**	0.30	9.88
1272.78	3660.28	4	**0.3192**	0.24	9.90

Mixed-Wet Uniform Dist. (SOR= 0.35)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1453.83	1794.97	0.5	**0.3194**	8.74
1453.83	2136.10	1	**0.3194**	8.74
1453.83	2484.17	1.5	**0.3209**	8.32
1453.83	2688.82	1.8	**0.3206**	8.39
1453.83	3507.48	3	**0.3201**	8.54
1453.83	4189.74	4	**0.3199**	8.59

Mixed-Wet Uniform Dist. (SOR= 0.35)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1720.98	2122.66	**0.3182**	9.07	21686385	0.964	1.23
1	1720.98	2524.68	**0.3183**	9.05	21689377	0.964	1.47
1.5	1720.98	2928.64	**0.3187**	8.94	21701489	0.965	1.70
1.8	1720.98	3173.67	**0.3192**	8.79	21718181	0.965	1.84
3	1720.98	4226.24	**0.3267**	6.66	21959046	0.976	2.46
4	1720.98	5309.88	**0.3427**	2.09	22492871	1.000	3.09

Mixed-Wet Uniform Dist. (SOR= 0.35)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	682.78	880.28	**0.3665**	4.71
1	682.78	1082.78	**0.3694**	5.55
1.5	682.78	1287.78	**0.3714**	6.10
1.8	682.78	1410.28	**0.3718**	6.24
3	552.78	1722.78	**0.4137**	18.19
4	552.78	2127.78	**0.4160**	18.85

Table 4.9: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform mixed-wet system (S_{OR}= 0.25).

Mixed-Wet Uniform Dist. 1 (S_{OR}= 0.35)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1260.28	1622.78	0.5	**0.3652**	1.98	4.34
1260.28	1984.03	1	**0.3648**	0.60	4.22
1272.78	2360.28	1.5	**0.3629**	0.42	3.69
1272.78	2577.78	1.8	**0.3629**	0.36	3.69
1272.78	3440.28	3	**0.3621**	0.24	3.46
1272.78	4157.78	4	**0.3617**	0.20	3.34

Mixed-Wet Dist. 1 (SOR= 0.35)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1453.79	1838.29	0.5	**0.3460**	1.15
1453.79	2221.39	1	**0.3455**	1.27
1453.79	2611.60	1.5	**0.3468**	0.91
1453.79	2840.59	1.8	**0.3464**	1.03
1453.79	3753.86	3	**0.3453**	1.35
1453.79	4512.48	4	**0.3447**	1.52

Mixed-Wet Dist. 1 (SOR= 0.35)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1721.01	2122.69	**0.3182**	9.07	21686737	0.964	1.23
1	1721.01	2524.38	**0.3182**	9.07	21686851	0.964	1.47
1.5	1721.01	2926.05	**0.3182**	9.07	21686727	0.964	1.70
1.8	1721.01	3167.13	**0.3183**	9.07	21687067	0.964	1.84
3	1721.01	4134.12	**0.3185**	9.00	21695429	0.964	2.40
4	1721.01	4950.37	**0.3193**	8.77	21720930	0.965	2.88

Mixed-Wet Dist. 1 (SOR= 0.35)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	635.28	867.78	**0.4226**	20.75
1	635.28	1100.28	**0.4226**	20.75
1.5	635.28	1335.28	**0.4235**	21.00
1.8	635.28	1475.28	**0.4235**	21.00
3	547.78	1947.78	**0.4600**	31.43
4	547.78	2422.78	**0.4611**	31.75

Table 4.10: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.35, Distribution 1).

Mixed-Wet Dist. 2 (SOR= 0.35)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1264.03	1582.78	0.5	**0.3353**	2.32	4.21
1264.03	1900.28	1	**0.3348**	0.71	4.34
1264.03	2219.03	1.5	**0.3350**	0.49	4.30
1277.78	2425.28	1.8	**0.3328**	0.42	4.90
1277.78	3190.28	3	**0.3328**	0.28	4.90
1277.78	3830.28	4	**0.3331**	0.22	4.84

Mixed-Wet Dist. 2 (SOR= 0.35)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1449.83	1795.49	0.5	**0.3229**	7.75
1449.83	2141.39	1	**0.3229**	7.73
1449.83	2495.39	1.5	**0.3247**	7.24
1449.83	2703.23	1.8	**0.3245**	7.30
1449.83	3534.72	3	**0.3240**	7.42
1449.83	4227.71	4	**0.3239**	7.47

Mixed-Wet Dist. 2 (SOR= 0.35)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1720.98	2123.01	**0.3184**	9.02	21692576	0.964	1.23
1	1720.98	2530.10	**0.3198**	8.63	21735930	0.966	1.47
1.5	1720.98	2962.13	**0.3247**	7.23	21893296	0.973	1.72
1.8	1720.98	3244.71	**0.3297**	5.80	22057233	0.980	1.89
3	1720.98	4714.23	**0.3670**	4.85	23356458	1.038	2.74
4	1720.98	6397.78	**0.4045**	15.58	24829364	1.104	3.72

Mixed-Wet Dist. 2 (SOR= 0.35)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	675.28	887.78	**0.3863**	10.36
1	675.28	1097.78	**0.3849**	9.96
1.5	675.28	1300.28	**0.3816**	9.02
1.8	675.28	1420.28	**0.3800**	8.57
3	547.78	1727.78	**0.4179**	19.41
4	547.78	2112.78	**0.4167**	19.04

Table 4.11: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.35, Distribution 2).

Mixed-Wet Dist. 3 (SOR= 0.35)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1267.78	1577.78	0.5	**0.3284**	2.40	6.16
1267.78	1887.78	1	**0.3284**	0.73	6.16
1267.78	2197.78	1.5	**0.3284**	0.51	6.16
1267.78	2397.78	1.8	**0.3312**	0.43	6.43
1267.78	3137.78	3	**0.3296**	0.29	6.66
1267.78	3755.28	4	**0.3291**	0.23	6.72

Mixed-Wet Dist. 3 (SOR= 0.35)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1451.85	1798.45	0.5	**0.3232**	7.67
1451.85	2145.13	1	**0.3232**	7.66
1451.85	2499.60	1.5	**0.3248**	7.19
1451.85	2707.78	1.8	**0.3246**	7.26
1451.85	3540.68	3	**0.3241**	7.39
1451.85	4234.89	4	**0.3240**	7.44

Mixed-Wet Dist. 3 (SOR= 0.35)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1721.01	2122.67	**0.3182**	12.71	21686371	0.964	1.23
1	1721.01	2524.54	**0.3183**	12.68	21688215	0.964	1.47
1.5	1721.01	2927.16	**0.3184**	12.62	21693076	0.964	1.70
1.8	1721.01	3169.97	**0.3187**	12.53	21700657	0.964	1.84
3	1721.01	4175.61	**0.3222**	11.11	21814228	0.970	2.43
4	1721.01	5132.81	**0.3314**	7.45	22112763	0.983	2.98

Mixed-Wet Dist. 3 (SOR= 0.35)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	677.78	887.78	**0.3826**	9.31
1	677.78	1095.28	**0.3812**	8.91
1.5	677.78	1305.28	**0.3817**	9.04
1.8	677.78	1432.78	**0.3823**	9.22
3	552.78	1757.78	**0.4208**	20.24
4	552.78	2172.78	**0.4229**	20.81

Table 4.12: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.35, Distribution 3).

Mixed-Wet Dist. 4 (SOR= 0.35)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1271.53	1569.03	0.5	**0.3188**	2.53	8.92
1271.53	1869.03	1	**0.3197**	0.77	8.66
1271.53	2167.78	1.5	**0.3197**	0.53	8.66
1282.78	2365.28	1.8	**0.3192**	0.45	8.81
1282.78	3085.28	3	**0.3190**	0.30	8.86
1282.78	3682.78	4	**0.3187**	0.24	8.95

Mixed-Wet Dist. 4 (SOR= 0.35)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1452.03	1792.02	0.5	**0.3189**	8.87
1452.03	2132.09	1	**0.3190**	8.87
1452.03	2479.30	1.5	**0.3205**	8.43
1452.03	2683.35	1.8	**0.3202**	8.50
1452.03	3499.62	3	**0.3198**	8.64
1452.03	4179.82	4	**0.3196**	8.70

Water-Wet Uniform Dist.4 (S_{OR}=0.35)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1720.99	2122.96	**0.3184**	9.03	21691553	0.964	1.23
1	1720.99	2529.66	**0.3197**	8.66	21732165	0.966	1.47
1.5	1720.99	2957.66	**0.3239**	7.46	21867702	0.972	1.72
1.8	1720.99	3234.97	**0.3283**	6.20	22010771	0.978	1.88
3	1720.99	4652.57	**0.3622**	3.48	23179968	1.030	2.70
4	1720.99	6292.51	**0.3991**	14.02	24603382	1.093	3.66

Mixed-Wet Dist. 4 (SOR= 0.35)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	680.28	880.28	**0.3703**	5.79
1	680.28	1082.78	**0.3717**	6.21
1.5	680.28	1285.28	**0.3722**	6.35
1.8	680.28	1405.28	**0.3719**	6.25
3	552.78	1712.78	**0.4116**	17.60
4	552.78	2112.78	**0.4137**	18.19

Table 4.13: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the mixed-wet system (S_{OR}= 0.35, Distribution 4).

Oil-Wet Uniform Dist. (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1467.78	1679.03	0.5	**0.2235**	3.86	10.60
1467.78	1890.28	1	**0.2235**	1.20	10.60
1467.78	2101.53	1.5	**0.2235**	0.82	10.60
1467.78	2229.03	1.8	**0.2237**	0.69	10.53
1480.28	2752.78	3	**0.2227**	0.44	10.91
1480.28	3177.78	4	**0.2228**	0.35	10.88

Oil-Wet Uniform Dist. (S_{OR}= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1676.29	1919.96	0.5	**0.2252**	9.90
1676.29	2163.63	1	**0.2252**	9.90
1676.29	2414.25	1.5	**0.2269**	9.24
1676.29	2560.42	1.8	**0.2266**	9.35
1676.29	3145.15	3	**0.2261**	9.58
1676.29	3632.47	4	**0.2259**	9.66

Oil-Wet Uniform Dist. (S_{OR}=0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.92	2269.93	**0.2245**	10.20	21966446	0.976	1.14
1	1982.92	2557.26	**0.2246**	10.16	21969307	0.976	1.29
1.5	1982.92	2845.52	**0.2248**	10.08	21975543	0.977	1.44
1.8	1982.92	3019.53	**0.2251**	9.98	21982641	0.977	1.52
3	1982.92	3738.91	**0.2279**	8.84	22063714	0.981	1.89
4	1982.92	4403.32	**0.2338**	6.48	22233564	0.988	2.22

Oil-Wet Uniform Dist. (S_{OR}= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	812.78	955.28	**0.2596**	3.85
1	812.78	1100.28	**0.2613**	4.52
1.5	812.78	1245.28	**0.2619**	4.74
1.8	812.78	1332.78	**0.2622**	4.89
3	672.78	1507.78	**0.2926**	17.06
4	672.78	1797.78	**0.2948**	17.92

Table 4.14: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform oil-wet system (S_{OR}= 0.25).

Oil-Wet Dist.1 (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1429.03	1714.03	0.5	**0.2851**	2.72	14.06
1429.03	1999.03	1	**0.2851**	0.83	14.06
1429.03	2284.03	1.5	**0.2851**	0.58	14.06
1442.78	2470.28	1.8	**0.2835**	0.49	13.39
1442.78	3150.28	3	**0.2829**	0.32	13.16
1442.78	3712.78	4	**0.2823**	0.26	12.92

Oil-Wet Dist.1 (SOR=0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1662.73	1952.93	0.5	**0.2588**	3.50
1662.73	2243.06	1	**0.2587**	3.49
1662.73	2541.36	1.5	**0.2605**	4.20
1662.73	2715.49	1.8	**0.2602**	4.09
1662.73	3410.48	3	**0.2595**	3.79
1662.73	3987.68	4	**0.2590**	3.61

Oil-Wet Dist.1 (SOR=0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.91	2269.82	**0.2244**	10.23	21964729	0.976	1.14
1	1982.91	2556.76	**0.2244**	10.22	21965010	0.976	1.29
1.5	1982.91	2843.60	**0.2244**	10.23	21964494	0.976	1.43
1.8	1982.91	3015.78	**0.2244**	10.23	21964678	0.976	1.52
3	1982.91	3704.55	**0.2245**	10.22	21965214	0.976	1.87
4	1982.91	4278.27	**0.2244**	10.22	21964881	0.976	2.16

Oil-Wet Dist.1 (SOR= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	790.28	982.78	**0.3276**	31.03
1	790.28	1172.78	**0.3261**	30.46
1.5	790.28	1360.28	**0.3247**	29.88
1.8	790.28	1472.78	**0.3242**	29.69
3	652.78	1742.78	**0.3576**	43.03
4	652.78	2107.78	**0.3578**	43.13

Table 4.15: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.25, Distribution 1).

Oil-Wet Dist.2 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1476.53	1666.53	0.5	**0.2047**	4.36	18.13
1476.53	1857.78	1	**0.2052**	1.35	17.91
1476.53	2049.03	1.5	**0.2054**	0.92	17.84
1476.53	2164.03	1.8	**0.2055**	0.78	17.79
1490.28	2640.28	3	**0.2046**	0.49	18.16
1490.28	3025.28	4	**0.2048**	0.38	18.09

Oil-Wet Dist.2 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1679.63	1903.99	0.5	**0.2108**	15.67
1679.63	2128.68	1	**0.2110**	15.62
1679.63	2350.76	1.5	**0.2103**	15.86
1679.63	2495.39	1.8	**0.2125**	15.01
1679.63	3035.93	3	**0.2121**	15.17
1679.63	3486.76	4	**0.2120**	15.21

Oil-Wet Dist.2 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.93	2270.66	**0.2249**	10.03	21979036	0.977	1.15
1	1982.93	2568.29	**0.2279**	8.83	22064072	0.981	1.30
1.5	1982.93	2896.50	**0.2350**	6.01	22267546	0.990	1.46
1.8	1982.93	3136.51	**0.2443**	2.30	22541022	1.002	1.58
3	1982.93	4401.52	**0.2890**	15.62	23961257	1.065	2.22
4	1982.93	5820.93	**0.3261**	30.44	25278289	1.123	2.94

Oil-Wet Dist.2 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	810.28	945.28	**0.2499**	0.03
1	810.28	1072.78	**0.2447**	2.12
1.5	810.28	1192.78	**0.2394**	4.25
1.8	810.28	1265.28	**0.2378**	4.89
3	677.78	1372.78	**0.2547**	1.89
4	677.78	1587.78	**0.2513**	0.52

Table 4.16: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.25, Distribution 2).

Oil-Wet Dist.3 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1444.03	1701.53	0.5	**0.2629**	3.07	5.15
1444.03	1955.28	1	**0.2615**	0.95	4.59
1444.03	2207.78	1.5	**0.2607**	0.66	4.27
1457.78	2372.78	1.8	**0.2585**	0.56	3.42
1457.78	2970.28	3	**0.2570**	0.37	2.79
1457.78	3465.28	4	**0.2561**	0.29	2.44

Oil-Wet Dist.3 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1667.67	1942.50	0.5	**0.2479**	0.84
1667.67	2216.77	1	**0.2477**	0.92
1667.67	2497.76	1.5	**0.2492**	0.34
1667.67	2661.67	1.8	**0.2488**	0.50
1667.67	3315.02	3	**0.2477**	0.92
1667.67	3857.10	4	**0.2471**	1.16

Oil-Wet Dist.3 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.90	2269.81	**0.2244**	10.22	21964677	0.976	1.14
1	1982.90	2556.74	**0.2244**	10.22	21964804	0.976	1.29
1.5	1982.90	2843.74	**0.2245**	10.22	21965277	0.976	1.43
1.8	1982.90	3015.94	**0.2245**	10.21	21965443	0.976	1.52
3	1982.90	3705.72	**0.2246**	10.17	21968529	0.976	1.87
4	1982.90	4282.44	**0.2248**	10.10	21973789	0.977	2.16

Oil-Wet Dist.3 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	797.78	972.78	**0.3049**	21.97
1	797.78	1142.78	**0.3019**	20.76
1.5	797.78	1310.28	**0.2999**	19.94
1.8	797.78	1412.78	**0.2999**	19.94
3	662.78	1637.78	**0.3290**	31.61
4	662.78	1957.78	**0.3282**	31.27

Table 4.17: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.25, Distribution 3).

Oil-Wet Dist.4 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1673.16	1917.83	0.5	**0.2263**	9.49
1673.16	2162.60	1	**0.2263**	9.47
1673.16	2414.68	1.5	**0.2281**	8.77
1673.16	2561.64	1.8	**0.2278**	8.88
1673.16	3149.83	3	**0.2273**	9.07
1673.16	3640.10	4	**0.2271**	9.14

Oil-Wet Dist.4 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1459.03	1677.78	0.5	**0.2307**	3.71	7.73
1459.03	1896.53	1	**0.2307**	1.15	7.73
1459.03	2115.28	1.5	**0.2307**	0.79	7.73
1459.03	2246.53	1.8	**0.2307**	0.67	7.73
1472.78	2790.28	3	**0.2297**	0.42	8.12
1472.78	3230.28	4	**0.2298**	0.33	8.09

Oil-Wet Dist.4 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.98	2270.64	**0.2249**	10.05	21978189	0.977	1.15
1	1982.98	2565.66	**0.2271**	9.16	22041440	0.980	1.29
1.5	1982.98	2885.62	**0.2328**	6.87	22205339	0.987	1.46
1.8	1982.98	3101.31	**0.2386**	4.57	22373183	0.994	1.56
3	1982.98	4149.07	**0.2669**	6.77	23238583	1.033	2.09
4	1982.98	5253.66	**0.2920**	16.78	24060223	1.069	2.65

Oil-Wet Dist.4 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	805.28	955.28	**0.2714**	8.57
1	805.28	1100.28	**0.2681**	7.25
1.5	805.28	1245.28	**0.2670**	6.80
1.8	805.28	1332.78	**0.2668**	6.73
3	667.78	1502.78	**0.2942**	17.67
4	667.78	1777.78	**0.2936**	17.43

Table 4.18: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.25, Distribution 4).

Oil-Wet Dist.5 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1457.78	1681.53	0.5	**0.2349**	3.62	6.05
1457.78	1901.53	1	**0.2334**	1.13	6.65
1457.78	2117.78	1.5	**0.2318**	0.78	7.26
1457.78	2247.78	1.8	**0.2314**	0.66	7.44
1457.78	2772.78	3	**0.2312**	0.42	7.53
1457.78	3192.78	4	**0.2293**	0.34	8.28

Oil-Wet Dist.5 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1671.36	1923.94	0.5	**0.2321**	7.16
1671.36	2170.35	1	**0.2299**	8.04
1671.36	2419.62	1.5	**0.2299**	8.06
1671.36	2563.24	1.8	**0.2287**	8.53
1671.36	3128.62	3	**0.2252**	9.93
1671.36	3591.66	4	**0.2231**	10.74

Oil-Wet Dist.5 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.92	2269.94	**0.2245**	10.20	21966680	0.976	1.14
1	1982.92	2556.81	**0.2245**	10.22	21965437	0.976	1.29
1.5	1982.92	2843.74	**0.2245**	10.22	21965316	0.976	1.43
1.8	1982.92	3015.82	**0.2244**	10.22	21964924	0.976	1.52
3	1982.92	3712.64	**0.2253**	9.89	21988461	0.977	1.87
4	1982.92	4294.98	**0.2257**	9.72	22000859	0.978	2.17

Oil-Wet Dist.5 (SOR= 0.25)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	800.28	957.78	**0.2824**	12.98
1	800.28	1102.78	**0.2743**	9.72
1.5	800.28	1242.78	**0.2693**	7.73
1.8	800.28	1322.78	**0.2662**	6.47
3	667.78	1462.78	**0.2841**	13.64
4	667.78	1707.78	**0.2802**	12.10

Table 4.19: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.25, Distribution 5).

Oil-Wet Uniform Dist. (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1176.53	1515.28	0.5	**0.3654**	2.12	8.65
1176.53	1854.03	1	**0.3654**	0.64	8.65
1176.53	2194.03	1.5	**0.3657**	0.45	8.57
1187.78	2412.78	1.8	**0.3643**	0.39	8.94
1187.78	3225.28	3	**0.3638**	0.26	9.05
1187.78	3902.78	4	**0.3636**	0.21	9.09

Oil-Wet Uniform Dist. (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1342.59	1732.43	0.5	**0.3674**	8.15
1342.59	2122.30	1	**0.3674**	8.15
1342.59	2519.13	1.5	**0.3688**	7.81
1342.59	2753.00	1.8	**0.3685**	7.87
1342.59	3688.66	3	**0.3681**	7.98
1342.59	4468.36	4	**0.3679**	8.02

Oil-Wet Uniform Dist. (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.00	2049.08	**0.3661**	8.48	21547521	0.958	1.29
1	1590.00	2508.37	**0.3661**	8.47	21549266	0.958	1.58
1.5	1590.00	2970.29	**0.3666**	8.35	21564961	0.958	1.87
1.8	1590.00	3251.48	**0.3673**	8.17	21589459	0.960	2.04
3	1590.00	4488.22	**0.3780**	5.51	21959103	0.976	2.82
4	1590.00	5836.57	**0.4004**	0.09	22780147	1.012	3.67

Oil-Wet Uniform Dist. (SOR= 0.4)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	617.78	845.28	**0.4241**	6.03
1	617.78	1075.28	**0.4255**	6.37
1.5	617.78	1307.78	**0.4268**	6.70
1.8	617.78	1447.78	**0.4274**	6.85
3	492.78	1827.78	**0.4745**	18.63
4	492.78	2292.78	**0.4773**	19.33

Table 4.20: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform oil-wet system (S_{OR}= 0.4).

Oil-Wet Dist.1 (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1144.03	1560.28	0.5	**0.4212**	1.63	5.30
1144.03	1976.53	1	**0.4212**	0.49	5.30
1157.78	2410.28	1.5	**0.4190**	0.35	4.75
1157.78	2657.78	1.8	**0.4185**	0.30	4.63
1157.78	3660.28	3	**0.4188**	0.20	4.69
1157.78	4492.78	4	**0.4186**	0.17	4.66

Oil-Wet Dist.1 (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1330.99	1771.58	0.5	**0.3983**	0.42
1330.99	2212.25	1	**0.3984**	0.41
1330.99	2661.30	1.5	**0.3999**	0.03
1330.99	2925.99	1.8	**0.3997**	0.08
1330.99	3984.52	3	**0.3992**	0.19
1330.99	4870.00	4	**0.3993**	0.17

Oil-Wet Dist.1 (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.06	2049.06	**0.3660**	8.50	21546598	0.958	1.29
1	1590.06	2508.10	**0.3660**	8.49	21546994	0.958	1.58
1.5	1590.06	2967.18	**0.3660**	8.49	21547299	0.958	1.87
1.8	1590.06	3242.73	**0.3661**	8.49	21547919	0.958	2.04
3	1590.06	4345.98	**0.3662**	8.45	21552118	0.958	2.73
4	1590.06	5272.39	**0.3667**	8.33	21568810	0.959	3.32

Oil-Wet Dist.1 (SOR= 0.4)				
	T_{bt}		S_o	Deviation (%)
k_d	cons.	part.		
0.5	597.78	877.78	**0.4837**	20.92
1	597.78	1155.28	**0.4826**	20.64
1.5	597.78	1435.28	**0.4829**	20.73
1.8	597.78	1602.78	**0.4829**	20.73
3	477.78	2087.78	**0.5290**	32.26
4	477.78	2642.78	**0.5311**	32.79

Table 4.21: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.4, Distribution 1).

Oil-Wet Dist.2 (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1159.03	1535.28	0.5	**0.3937**	1.86	1.58
1159.03	1912.78	1	**0.3941**	0.56	1.49
1159.03	2292.78	1.5	**0.3947**	0.39	1.32
1170.28	2532.78	1.8	**0.3928**	0.34	1.81
1170.28	3445.28	3	**0.3932**	0.23	1.70
1170.28	4202.78	4	**0.3931**	0.19	1.72

Oil-Wet Dist.2 (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1335.93	1742.43	0.5	**0.3783**	5.42
1335.93	2149.40	1	**0.3785**	5.38
1335.93	2564.59	1.5	**0.3801**	4.98
1335.93	2809.19	1.8	**0.3799**	5.02
1335.93	3787.52	3	**0.3795**	5.12
1335.93	4602.80	4	**0.3794**	5.15

Oil-Wet Dist.2 (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.03	2049.29	**0.3662**	8.46	21550725	0.958	1.29
1	1590.03	2516.88	**0.3683**	7.94	21622357	0.961	1.58
1.5	1590.03	3032.05	**0.3768**	5.80	21918753	0.974	1.91
1.8	1590.03	3382.42	**0.3851**	3.73	22214509	0.987	2.13
3	1590.03	5259.52	**0.4348**	8.70	24168030	1.074	3.31
4	1590.03	7147.37	**0.4663**	16.58	25595594	1.138	4.50

Oil-Wet Dist.2 (SOR= 0.4)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	602.78	857.78	**0.4583**	14.58
1	602.78	1105.28	**0.4546**	13.66
1.5	602.78	1342.78	**0.4501**	12.52
1.8	602.78	1485.28	**0.4485**	12.13
3	482.78	1872.78	**0.4897**	22.43
4	482.78	2322.78	**0.4879**	21.98

Table 4.22: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.4, Distribution 2).

Oil-Wet Dist.3 (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1161.53	1526.53	0.5	**0.3859**	1.93	3.52
1161.53	1887.78	1	**0.3847**	0.59	3.82
1161.53	2247.78	1.5	**0.3840**	0.41	3.99
1172.78	2477.78	1.8	**0.3820**	0.36	4.49
1172.78	3335.28	3	**0.3807**	0.24	4.83
1172.78	4050.28	4	**0.3802**	0.20	4.95

Oil-Wet Dist.3 (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1337.09	1739.46	0.5	**0.3757**	6.07
1337.09	2141.64	1	**0.3757**	6.08
1337.09	2551.44	1.5	**0.3771**	5.72
1337.09	2792.71	1.8	**0.3769**	5.78
1337.09	3757.91	3	**0.3764**	5.91
1337.09	4562.15	4	**0.3762**	5.96

Oil-Wet Dist.3 (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.01	2049.15	**0.3661**	8.48	21548609	0.958	1.29
1	1590.01	2508.26	**0.3661**	8.48	21548378	0.958	1.58
1.5	1590.01	2967.84	**0.3662**	8.46	21550965	0.958	1.87
1.8	1590.01	3244.42	**0.3663**	8.42	21555789	0.958	2.04
3	1590.01	4380.17	**0.3691**	7.74	21649757	0.962	2.75
4	1590.01	5453.49	**0.3779**	5.52	21957455	0.976	3.43

Oil-Wet Dist.3 (SOR= 0.4)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	607.78	852.78	**0.4464**	11.59
1	607.78	1095.28	**0.4451**	11.27
1.5	607.78	1337.78	**0.4447**	11.17
1.8	607.78	1485.28	**0.4451**	11.27
3	482.78	1882.78	**0.4915**	22.88
4	482.78	2362.78	**0.4933**	23.32

Table 4.23: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.4, Distribution 3).

Oil-Wet Dist.4 (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1170.28	1519.03	0.5	**0.3734**	2.04	6.64
1170.28	1866.53	1	**0.3730**	0.62	6.75
1170.28	2212.78	1.5	**0.3726**	0.44	6.85
1182.78	2437.78	1.8	**0.3709**	0.37	7.28
1182.78	3275.28	3	**0.3710**	0.25	7.26
1182.78	3972.78	4	**0.3710**	0.20	7.26

Oil-Wet Dist.4 (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1339.97	1729.74	0.5	**0.3678**	8.05
1339.97	2119.56	1	**0.3678**	8.05
1339.97	2516.87	1.5	**0.3693**	7.68
1339.97	2750.75	1.8	**0.3690**	7.74
1339.97	3686.64	3	**0.3686**	7.85
1339.97	4466.54	4	**0.3684**	7.90

Oil-Wet Dist.4 (SOR= 0.4)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	612.78	845.28	**0.4314**	7.86
1	612.78	1077.78	**0.4314**	7.86
1.5	612.78	1310.28	**0.4314**	7.86
1.8	612.78	1447.78	**0.4309**	7.71
3	487.78	1827.78	**0.4780**	19.50
4	487.78	2277.78	**0.4785**	19.62

Oil-Wet Dist.4 (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.11	2049.33	**0.3661**	8.47	21550809	0.958	1.29
1	1590.11	2517.15	**0.3683**	7.93	21624680	0.961	1.58
1.5	1590.11	3023.26	**0.3753**	6.17	21868605	0.972	1.90
1.8	1590.11	3382.94	**0.3851**	3.72	22217263	0.987	2.13
3	1590.11	5250.79	**0.4342**	8.55	24143456	1.073	3.30
4	1590.11	7322.88	**0.4740**	18.51	25973018	1.154	4.61

Table 4.24: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the oil-wet system (S_{OR}= 0.4, Distribution 4).

Strongly Oil-Wet Uniform Dist. (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1676.22	1919.88	0.5	**0.2252**	9.90
1676.22	2163.55	1	**0.2252**	9.90
1676.22	2414.21	1.5	**0.2269**	9.24
1676.22	2560.38	1.8	**0.2266**	9.35
1676.22	3145.16	3	**0.2261**	9.58
1676.22	3632.41	4	**0.2259**	9.66

Strongly Oil-Wet Uniform Dist. (S_{OR}= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1467.78	1679.03	0.5	**0.2235**	3.86	10.60
1467.78	1890.28	1	**0.2235**	1.20	10.60
1467.78	2101.53	1.5	**0.2235**	0.82	10.60
1467.78	2229.03	1.8	**0.2237**	0.69	10.53
1480.28	2752.78	3	**0.2227**	0.44	10.91
1480.28	3177.78	4	**0.2228**	0.35	10.88

Strongly Oil-Wet Uniform Dist. (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.91	2269.89	**0.2245**	10.21	21965925	0.976	1.14
1	1982.91	2557.24	**0.2246**	10.16	21969120	0.976	1.29
1.5	1982.91	2845.52	**0.2248**	10.07	21975517	0.977	1.44
1.8	1982.91	3019.51	**0.2251**	9.98	21982518	0.977	1.52
3	1982.91	3738.78	**0.2279**	8.84	22063279	0.981	1.89
4	1982.91	4403.27	**0.2338**	6.48	22233377	0.988	2.22

Strongly Oil-Wet Uniform Dist. (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	812.78	955.28	**0.2596**	3.85
1	812.78	1100.28	**0.2613**	4.52
1.5	812.78	1245.28	**0.2619**	4.74
1.8	812.78	1332.78	**0.2622**	4.89
3	672.78	1507.78	**0.2926**	17.06
4	672.78	1797.78	**0.2948**	17.92

Table 4.25: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform strongly oil-wet system (S_{OR}= 0.25).

Strongly Oil-Wet Dist.1 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1396.53	1679.03	0.5	**0.2880**	2.74	15.22
1396.53	1961.53	1	**0.2880**	0.84	15.22
1396.53	2242.78	1.5	**0.2877**	0.58	15.10
1410.28	2425.28	1.8	**0.2856**	0.50	14.25
1410.28	3097.78	3	**0.2851**	0.32	14.05
1410.28	3657.78	4	**0.2849**	0.26	13.96

Strongly Oil-Wet Dist.1 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1633.32	1922.51	0.5	**0.2615**	4.61
1633.32	2211.55	1	**0.2615**	4.58
1633.32	2508.65	1.5	**0.2632**	5.29
1633.32	2682.19	1.8	**0.2630**	5.18
1633.32	3374.80	3	**0.2622**	4.89
1633.32	3950.17	4	**0.2618**	4.71

Strongly Oil-Wet Dist.1 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.99	2269.90	**0.2244**	10.23	21965319	0.976	1.14
1	1982.99	2556.86	**0.2244**	10.22	21965875	0.976	1.29
1.5	1982.99	2843.74	**0.2244**	10.23	21965570	0.976	1.43
1.8	1982.99	3015.88	**0.2244**	10.23	21965516	0.976	1.52
3	1982.99	3704.66	**0.2244**	10.22	21966051	0.976	1.87
4	1982.99	4278.53	**0.2244**	10.22	21966010	0.976	2.16

Strongly Oil-Wet Dist.1 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	767.78	957.78	**0.3311**	32.43
1	767.78	1145.28	**0.3296**	31.85
1.5	767.78	1332.78	**0.3291**	31.65
1.8	767.78	1445.28	**0.3290**	31.58
3	632.78	1712.78	**0.3626**	45.05
4	632.78	2072.78	**0.3626**	45.05

Table 4.26: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.25, Distribution 1).

Strongly Oil-Wet Dist.2 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1484.03	1674.03	0.5	**0.2039**	4.36	
1484.03	1865.28	1	**0.2044**	1.35	17.91
1484.03	2057.78	1.5	**0.2049**	0.92	17.84
1484.03	2172.78	1.8	**0.2050**	0.78	17.79
1502.78	2652.78	3	**0.2032**	0.49	18.16
1502.78	3037.78	4	**0.2034**	0.38	18.09

Strongly Oil-Wet Dist.2 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1679.63	1903.99	0.5	**0.2108**	15.67
1679.63	2128.68	1	**0.2110**	15.62
1679.63	2350.76	1.5	**0.2103**	15.86
1679.63	2495.39	1.8	**0.2125**	15.01
1679.63	3035.93	3	**0.2121**	15.17
1679.63	3486.76	4	**0.2120**	15.21

Strongly Oil-Wet Dist.2 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.93	2270.16	**0.2246**	10.15	21970366	0.976	1.14
1	1982.93	2561.45	**0.2259**	9.66	22005267	0.978	1.29
1.5	1982.93	2872.98	**0.2303**	7.87	22132868	0.984	1.45
1.8	1982.93	3076.18	**0.2345**	6.21	22253056	0.989	1.55
3	1982.93	4188.78	**0.2705**	8.20	23352048	1.038	2.11
4	1982.93	5544.76	**0.3099**	23.96	24685162	1.097	2.80

Strongly Oil-Wet Dist.2 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	812.78	950.28	**0.2528**	1.12
1	812.78	1080.28	**0.2476**	0.95
1.5	812.78	1202.78	**0.2424**	3.06
1.8	812.78	1275.28	**0.2402**	3.92
3	677.78	1392.78	**0.2602**	4.06
4	677.78	1607.78	**0.2554**	2.17

Table 4.27: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.25, Distribution 2).

Strongly Oil-Wet Dist.3 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1437.78	1692.78	0.5	**0.2618**	3.10	4.73
1437.78	1947.78	1	**0.2618**	0.95	4.73
1437.78	2199.03	1.5	**0.2609**	0.66	4.36
1450.28	2365.28	1.8	**0.2595**	0.56	3.81
1450.28	2960.28	3	**0.2576**	0.37	3.06
1450.28	3452.78	4	**0.2566**	0.29	2.64

Strongly Oil-Wet Dist.3 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1662.09	1936.40	0.5	**0.2482**	0.73
1662.09	2210.16	1	**0.2480**	0.81
1662.09	2490.62	1.5	**0.2494**	0.23
1662.09	2654.22	1.8	**0.2490**	0.39
1662.09	3306.33	3	**0.2480**	0.81
1662.09	3847.52	4	**0.2474**	1.04

Strongly Oil-Wet Dist.3 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	792.78	967.78	**0.3063**	22.51
1	792.78	1137.78	**0.3032**	21.29
1.5	792.78	1305.28	**0.3012**	20.47
1.8	792.78	1405.28	**0.3003**	20.13
3	657.78	1627.78	**0.3296**	31.82
4	657.78	1952.78	**0.3298**	31.94

Strongly Oil-Wet Dist.3 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.98	2269.84	**0.2244**	10.24	21964521	0.976	1.14
1	1982.98	2556.83	**0.2244**	10.22	21965617	0.976	1.29
1.5	1982.98	2843.81	**0.2244**	10.22	21965945	0.976	1.43
1.8	1982.98	3016.02	**0.2245**	10.22	21966155	0.976	1.52
3	1982.98	3705.99	**0.2246**	10.17	21969783	0.976	1.87
4	1982.98	4283.41	**0.2248**	10.07	21976425	0.977	2.16

Table 4.28: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.25, Distribution 3).

Strongly Oil-Wet Dist.4 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1673.20	1917.87	0.5	**0.2263**	3.34	9.49
1673.20	2162.68	1	**0.2263**	1.03	9.47
1470.28	2130.28	1.5	**0.2303**	0.78	7.87
1470.28	2260.28	1.8	**0.2299**	0.67	8.05
1470.28	2787.78	3	**0.2300**	0.42	8.00
1470.28	3227.78	4	**0.2301**	0.33	7.97

Strongly Oil-Wet Dist.4 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1676.27	1919.89	0.5	**0.2263**	9.49
1676.27	2163.57	1	**0.2263**	9.47
1676.27	2414.75	1.5	**0.2281**	8.77
1676.27	2561.75	1.8	**0.2278**	8.88
1676.27	3149.94	3	**0.2273**	9.07
1676.27	3640.10	4	**0.2271**	9.14

Strongly Oil-Wet Dist.4 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.95	2270.28	**0.2247**	10.13	21972259	0.977	1.14
1	1982.95	2563.03	**0.2263**	9.47	22018865	0.979	1.29
1.5	1982.95	2874.62	**0.2306**	7.74	22142264	0.984	1.45
1.8	1982.95	3073.38	**0.2340**	6.40	22239748	0.988	1.55
3	1982.95	4101.16	**0.2626**	5.03	23101218	1.027	2.07
4	1982.95	5179.31	**0.2872**	14.89	23900349	1.062	2.61

Strongly Oil-Wet Dist.4 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	802.78	952.78	**0.2720**	8.82
1	802.78	1100.28	**0.2704**	8.15
1.5	802.78	1245.28	**0.2687**	7.49
1.8	802.78	1332.78	**0.2684**	7.34
3	667.78	1502.78	**0.2942**	17.67
4	667.78	1782.78	**0.2945**	17.80

Table 4.29: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.25, Distribution 4).

Strongly Oil-Wet Dist.5 (SOR= 0.25)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1465.28	1692.78	0.5	**0.2369**	3.55	5.22
1465.28	1915.28	1	**0.2350**	1.11	6.02
1465.28	2132.78	1.5	**0.2329**	0.77	6.82
1465.28	2267.78	1.8	**0.2333**	0.65	6.69
1465.28	2775.28	3	**0.2296**	0.42	8.16
1465.28	3200.28	4	**0.2284**	0.34	8.64

Strongly Oil-Wet Dist.5 (SOR= 0.25)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1673.83	1928.58	0.5	**0.2334**	6.66
1673.83	2177.15	1	**0.2312**	7.53
1673.83	2421.27	1.5	**0.2294**	8.24
1673.83	2566.09	1.8	**0.2285**	8.61
1673.83	3136.19	3	**0.2255**	9.78
1673.83	3603.18	4	**0.2237**	10.52

Strongly Oil-Wet Dist.5 (SOR= 0.25)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	795.28	955.28	**0.2869**	14.77
1	795.28	1102.78	**0.2788**	11.54
1.5	795.28	1245.28	**0.2739**	9.56
1.8	795.28	1327.78	**0.2711**	8.45
3	662.78	1472.78	**0.2895**	15.78
4	662.78	1717.78	**0.2847**	13.87

Strongly Oil-Wet Dist.5 (SOR= 0.25)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1982.90	2269.84	**0.2245**	10.22	21965239	0.976	1.14
1	1982.90	2556.84	**0.2245**	10.21	21965693	0.976	1.29
1.5	1982.90	2843.78	**0.2245**	10.21	21965535	0.976	1.43
1.8	1982.90	3015.91	**0.2245**	10.22	21965282	0.976	1.52
3	1982.90	3706.11	**0.2246**	10.15	21969663	0.976	1.87
4	1982.90	4298.16	**0.2259**	9.62	22007567	0.978	2.17

Table 4.30: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.25, Distribution 5).

Strongly Oil-Wet Uniform Dist. (SOR= 0.4)					
cons. tmode	part. tmode	kd	Predicted So	Error (%)	Deviation (%)
1176.53	1515.28	0.5	**0.3654**	2.12	8.65
1176.53	1854.03	1	**0.3654**	0.64	8.65
1176.53	2194.03	1.5	**0.3657**	0.45	8.57
1187.78	2412.78	1.8	**0.3643**	0.39	8.94
1187.78	3225.28	3	**0.3638**	0.26	9.05
1187.78	3902.78	4	**0.3636**	0.21	9.09

Strongly Oil-Wet Uniform Dist. (SOR= 0.4)				
cons. t50%	part. t50%	kd	Predicted So	Deviation (%)
1342.63	1732.49	0.5	**0.3674**	8.15
1342.63	2122.34	1	**0.3674**	8.15
1342.63	2519.15	1.5	**0.3688**	7.81
1342.63	2753.03	1.8	**0.3685**	7.87
1342.63	3688.64	3	**0.3681**	7.98
1342.63	4468.37	4	**0.3679**	8.02

Strongly Oil-Wet Uniform Dist. (SOR= 0.4)							
kd	mrtcons	mrtpart	SOR	ariation (%	Vp (cft)	Swept Vol %	R
0.5	1590.04	2049.11	**0.3661**	8.49	21547668	0.958	1.29
1	1590.04	2508.42	**0.3661**	8.47	21549710	0.958	1.58
1.5	1590.04	2970.35	**0.3666**	8.36	21565386	0.958	1.87
1.8	1590.04	3251.34	**0.3673**	8.18	21588926	0.960	2.04
3	1590.04	4488.23	**0.3779**	5.51	21959379	0.976	2.82
4	1590.04	5836.59	**0.4004**	0.09	22780445	1.012	3.67

Strongly Oil-Wet Uniform Dist. (SOR= 0.4)				
	Tbt		So	Deviation (%)
kd	cons.	part.		
0.5	617.78	845.28	**0.4241**	6.03
1	617.78	1075.28	**0.4255**	6.37
1.5	617.78	1307.78	**0.4268**	6.70
1.8	617.78	1447.78	**0.4274**	6.85
3	492.78	1827.78	**0.4745**	18.63
4	492.78	2292.78	**0.4773**	19.33

Table 4.31: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform strongly oil-wet system (S_{OR}= 0.4).

Strongly Oil-Wet Dist.1 (SOR= 0.4)					
cons. tmode	part. tmode	kd	Predicted So	Error (%)	Deviation (%)
1109.03	1550.28	0.5	**0.4431**	1.50	10.78
1109.03	1991.53	1	**0.4431**	0.45	10.78
1120.28	2445.28	1.5	**0.4409**	0.32	10.22
1120.28	2710.28	1.8	**0.4409**	0.28	10.22
1120.28	3762.78	3	**0.4402**	0.19	10.04
1120.28	4674.78	4	**0.4423**	0.16	10.59

Strongly Oil-Wet Dist.1 (SOR= 0.4)				
cons. t50%	part. t50%	kd	Predicted So	Deviation (%)
1309.38	1764.08	0.5	**0.4099**	2.47
1309.38	2218.48	1	**0.4098**	2.45
1309.38	2681.31	1.5	**0.4113**	2.81
1309.38	2953.75	1.8	**0.4110**	2.74
1309.38	4040.97	3	**0.4102**	2.54
1309.38	4968.99	4	**0.4113**	2.83

Strongly Oil-Wet Dist.1 (SOR= 0.4)							
kd	mrtcons	mrtpart	SOR	Variation (%)	Vp (cft)	Swept Vol %	R
0.5	1590.12	2049.15	**0.3660**	8.49	21547644	0.958	1.29
1	1590.12	2508.12	**0.3660**	8.50	21547176	0.958	1.58
1.5	1590.12	2967.20	**0.3660**	8.49	21547600	0.958	1.87
1.8	1590.12	3242.67	**0.3660**	8.49	21547828	0.958	2.04
3	1590.12	4344.65	**0.3661**	8.49	21548643	0.958	2.73
4	1590.12	5264.02	**0.3661**	8.47	21551206	0.958	3.31

Strongly Oil-Wet Dist.1 (SOR= 0.4)				
	Tbt		So	Deviation (%)
kd	cons.	part.		
0.5	572.78	870.28	**0.5095**	27.38
1	572.78	1165.28	**0.5085**	27.12
1.5	572.78	1455.28	**0.5067**	26.67
1.8	572.78	1630.28	**0.5063**	26.59
3	452.78	2142.78	**0.5544**	38.60
4	452.78	2707.78	**0.5546**	38.65

Table 4.32: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.4, Distribution 1).

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Strongly Oil-Wet Dist.2 (SOR= 0.4)					
cons. tmode	part. tmode	kd	Predicted So	Error (%)	Deviation (%)
1152.78	1519.03	0.5	**0.3885**	1.92	2.87
1152.78	1886.53	1	**0.3889**	0.58	2.76
1152.78	2254.03	1.5	**0.3891**	0.41	2.73
1165.28	2492.78	1.8	**0.3876**	0.35	3.10
1165.28	3375.28	3	**0.3873**	0.23	3.17
1165.28	4115.28	4	**0.3876**	0.19	3.10

Strongly Oil-Wet Dist.2 (SOR= 0.4)				
cons. t50%	part. t50%	kd	Predicted So	Deviation (%)
1332.87	1734.35	0.5	**0.3759**	6.01
1332.87	2136.22	1	**0.3761**	5.98
1332.87	2545.93	1.5	**0.3776**	5.59
1332.87	2787.32	1.8	**0.3774**	5.64
1332.87	3753.16	3	**0.3771**	5.74
1332.87	4558.10	4	**0.3769**	5.77

Strongly Oil-Wet Dist.2 (SOR= 0.4)							
kd	mrtcons	mrtpart	SOR	Variation (%)	Vp (cft)	Swept Vol %	R
0.5	1590.01	2049.40	**0.3662**	8.44	21552901	0.958	1.29
1	1590.01	2522.68	**0.3697**	7.57	21672228	0.963	1.59
1.5	1590.01	3076.58	**0.3840**	4.01	22173760	0.986	1.93
1.8	1590.01	3447.47	**0.3936**	1.61	22524895	1.001	2.17
3	1590.01	5447.96	**0.4471**	11.79	24707549	1.098	3.43
4	1590.01	7015.67	**0.4604**	15.09	25312613	1.125	4.41

Strongly Oil-Wet Dist.2 (SOR= 0.4)				
	Tbt		So	Deviation (%)
kd	cons.	part.		
0.5	595.28	847.78	**0.4590**	14.74
1	595.28	1090.28	**0.4540**	13.50
1.5	595.28	1327.78	**0.4507**	12.66
1.8	595.28	1467.78	**0.4488**	12.20
3	472.78	1847.78	**0.4922**	23.06
4	472.78	2297.78	**0.4911**	22.78

Table 4.33: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.4, Distribution 2).

Strongly Oil-Wet Dist.3 (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1144.03	1527.78	0.5	**0.4015**	1.80	0.38
1144.03	1909.03	1	**0.4007**	0.55	0.18
1144.03	2287.78	1.5	**0.3999**	0.39	0.01
1155.28	2527.78	1.8	**0.3976**	0.33	0.60
1155.28	3430.28	3	**0.3963**	0.23	0.93
1155.28	4175.28	4	**0.3952**	0.19	1.19

Strongly Oil-Wet Dist.3 (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1329.21	1741.66	0.5	**0.3829**	4.26
1329.21	2152.10	1	**0.3824**	4.41
1329.21	2569.92	1.5	**0.3836**	4.10
1329.21	2815.31	1.8	**0.3831**	4.21
1329.21	3795.51	3	**0.3821**	4.47
1329.21	4611.13	4	**0.3817**	4.58

Strongly Oil-Wet Dist.3 (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.03	2049.09	**0.3661**	8.49	21547298	0.958	1.29
1	1590.03	2508.20	**0.3661**	8.48	21547810	0.958	1.58
1.5	1590.03	2967.80	**0.3662**	8.46	21550794	0.958	1.87
1.8	1590.03	3244.22	**0.3663**	8.43	21554903	0.958	2.04
3	1590.03	4367.70	**0.3680**	8.00	21614171	0.961	2.75
4	1590.03	5369.58	**0.3727**	6.81	21777377	0.968	3.38

Strongly Oil-Wet Dist.3 (SOR= 0.4)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	595.28	847.78	**0.4590**	14.74
1	595.28	1090.28	**0.4540**	13.50
1.5	595.28	1327.78	**0.4507**	12.66
1.8	595.28	1467.78	**0.4488**	12.20
3	472.78	1937.78	**0.5081**	27.02
4	472.78	2432.78	**0.5089**	27.24

Table 4.34: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.4, Distribution 3).

Strongly Oil-Wet Dist.4 (SOR= 0.4)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1166.53	1514.03	0.5	**0.3733**	2.05	6.66
1166.53	1860.28	1	**0.3729**	0.62	6.77
1166.53	2207.78	1.5	**0.3731**	0.44	6.73
1177.78	2432.78	1.8	**0.3719**	0.37	7.04
1177.78	3582.78	3	**0.4050**	0.21	1.25
1177.78	4445.28	4	**0.4095**	0.17	2.38

Strongly Oil-Wet Dist.4 (SOR= 0.4)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1339.89	1727.78	0.5	**0.3667**	8.33
1339.89	2115.79	1	**0.3667**	8.32
1339.89	2511.24	1.5	**0.3682**	7.95
1339.89	2744.13	1.8	**0.3680**	8.00
1339.89	4054.42	3	**0.4031**	0.77
1339.89	4473.58	4	**0.3690**	7.76

Strongly Oil-Wet Dist.4 (SOR= 0.4)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.07	2049.55	**0.3663**	8.44	21554927	0.958	1.29
1	1590.07	2526.58	**0.3707**	7.33	21705713	0.965	1.59
1.5	1590.07	3084.17	**0.3852**	3.71	22217388	0.987	1.94
1.8	1590.07	3476.92	**0.3973**	0.67	22665684	1.007	2.19
3	1590.07	5538.02	**0.4528**	13.21	24965765	1.110	3.48
4	1590.07	7281.53	**0.4723**	18.06	25883981	1.150	4.58

Strongly Oil-Wet Dist.4 (SOR= 0.4)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	607.78	842.78	**0.4361**	9.02
1	607.78	1075.28	**0.4348**	8.69
1.5	607.78	1305.28	**0.4335**	8.36
1.8	607.78	1442.78	**0.4329**	8.22
3	487.78	1817.78	**0.4761**	19.03
4	487.78	2262.78	**0.4764**	19.09

Table 4.35: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.4, Distribution 4).

Strongly Oil-Wet Uniform Dist. (SOR= 0.5)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
982.78	1402.78	0.5	**0.4608**	1.55	7.83
982.78	1831.53	1	**0.4634**	0.46	7.32
982.78	2254.03	1.5	**0.4630**	0.33	7.39
992.78	2522.78	1.8	**0.4613**	0.28	7.75
992.78	3542.78	3	**0.4613**	0.20	7.75
992.78	4387.78	4	**0.4609**	0.16	7.82

Strongly Oil-Wet Uniform Dist. (SOR= 0.5)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1120.18	1607.49	0.5	**0.4653**	6.95
1120.18	2094.81	1	**0.4653**	6.95
1120.18	2589.08	1.5	**0.4664**	6.71
1120.18	2881.47	1.8	**0.4662**	6.75
1120.18	4051.02	3	**0.4659**	6.83
1120.18	5045.25	4	**0.4669**	6.61

Strongly Oil-Wet Uniform Dist. (SOR= 0.5)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	490.28	770.28	**0.5332**	6.64
1	490.28	1057.78	**0.5365**	7.30
1.5	490.28	1350.28	**0.5390**	7.81
1.8	490.28	1525.28	**0.5398**	7.95
3	672.78	2042.78	**0.4043**	19.13
4	672.78	2627.78	**0.4208**	15.84

Strongly Oil-Wet Uniform Dist. (SOR= 0.5)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1328.09	1902.00	**0.4636**	7.28	21270355	0.945	1.43
1	1328.09	2476.09	**0.4636**	7.27	21271997	0.945	1.86
1.5	1328.09	3053.92	**0.4642**	7.16	21293890	0.946	2.30
1.8	1328.09	3408.03	**0.4653**	6.95	21336588	0.948	2.57
3	1328.09	5066.63	**0.4841**	3.18	22115450	0.983	3.81
4	1328.09	7081.14	**0.5199**	3.98	23765605	1.056	5.33

Table 4.36: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the uniform strongly oil-wet system (S_{OR}= 0.5).

Strongly Oil-Wet Dist.1 (SOR= 0.5)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
937.78	1439.03	0.5	**0.5167**	1.21	3.34
937.78	1939.03	1	**0.5164**	0.36	3.27
947.78	2455.28	1.5	**0.5147**	0.26	2.93
947.78	2755.28	1.8	**0.5144**	0.23	2.89
947.78	3735.28	3	**0.4950**	0.18	0.99
947.78	4992.78	4	**0.5162**	0.14	3.24

Strongly Oil-Wet Dist.1 (SOR= 0.5)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1099.53	1635.14	0.5	**0.4935**	1.30
1099.53	2170.49	1	**0.4934**	1.32
1099.53	2714.24	1.5	**0.4947**	1.06
1099.53	3035.53	1.8	**0.4945**	1.10
1099.53	4344.63	3	**0.4959**	0.82
1099.53	5415.63	4	**0.4953**	0.94

Strongly Oil-Wet Dist.1 (SOR= 0.5)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1328.10	1901.91	**0.4636**	7.29	21268799	0.945	1.43
1	1328.10	2475.70	**0.4635**	7.29	21268572	0.945	1.86
1.5	1328.10	3049.66	**0.4636**	7.29	21269513	0.945	2.30
1.8	1328.10	3394.22	**0.4636**	7.28	21270712	0.945	2.56
3	1328.10	4783.59	**0.4645**	7.11	21304964	0.947	3.60
4	1328.10	6004.25	**0.4682**	6.37	21452779	0.953	4.52

Strongly Oil-Wet Dist.1 (SOR= 0.5)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	462.78	795.28	**0.5897**	17.93
1	462.78	1130.28	**0.5906**	18.11
1.5	462.78	1467.78	**0.5915**	18.29
1.8	462.78	1667.78	**0.5913**	18.25
3	352.78	2292.78	**0.6470**	29.40
4	352.78	2957.78	**0.6486**	29.73

Table 4.37: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.5, Distribution 1).

Strongly Oil-Wet Dist.2 (SOR= 0.5)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
961.53	1420.28	0.5	**0.4883**	1.37	2.34
961.53	1879.03	1	**0.4883**	0.41	2.34
972.78	2352.78	1.5	**0.4861**	0.29	2.79
972.78	2630.28	1.8	**0.4863**	0.26	2.74
972.78	3735.28	3	**0.4863**	0.18	2.74
972.78	4692.78	4	**0.4888**	0.15	2.25

Strongly Oil-Wet Dist.2 (SOR= 0.5)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1111.27	1614.49	0.5	**0.4752**	4.95
1111.27	2117.87	1	**0.4753**	4.94
1111.27	2650.14	1.5	**0.4800**	3.99
1111.27	2952.83	1.8	**0.4793**	4.13
1111.27	4162.88	3	**0.4779**	4.42
1111.27	5170.78	4	**0.4773**	4.53

Strongly Oil-Wet Dist.2 (SOR= 0.5)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1328.15	1902.02	**0.4636**	15.89	21270206	0.945	1.43
1	1328.15	2483.47	**0.4652**	16.30	21335336	0.948	1.87
1.5	1328.15	3117.07	**0.4731**	18.28	21655757	0.962	2.35
1.8	1328.15	3563.98	**0.4833**	20.82	22081135	0.981	2.68
3	1328.15	5899.77	**0.5343**	33.58	24501603	1.089	4.44
4	1328.15	8486.62	**0.5740**	43.50	26784603	1.190	6.39

Strongly Oil-Wet Dist.2 (SOR= 0.5)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	472.78	780.28	**0.5654**	13.07
1	472.78	1085.28	**0.5644**	12.87
1.5	472.78	1387.78	**0.5634**	12.67
1.8	472.78	1570.28	**0.5633**	12.65
3	362.78	2112.78	**0.6166**	23.31
4	362.78	2707.78	**0.6177**	23.55

Table 4.38: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.5, Distribution 2).

Strongly Oil-Wet Dist.3 (SOR= 0.5)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
1170.28	1519.03	0.5	**0.3734**	2.04	6.64
1170.28	1866.53	1	**0.3730**	0.62	6.75
1170.28	2212.78	1.5	**0.3726**	0.44	6.85
1182.78	2437.78	1.8	**0.3709**	0.37	7.28
1182.78	3275.28	3	**0.3710**	0.25	7.26
1182.78	3972.78	4	**0.3710**	0.20	7.26

Strongly Oil-Wet Dist.3 (SOR= 0.5)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1339.97	1729.74	0.5	**0.3678**	8.05
1339.97	2119.56	1	**0.3678**	8.05
1339.97	2516.87	1.5	**0.3693**	7.68
1339.97	2750.75	1.8	**0.3690**	7.74
1339.97	3686.64	3	**0.3686**	7.85
1339.97	4466.54	4	**0.3684**	7.90

Strongly Oil-Wet Dist.3 (SOR= 0.5)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1590.11	2049.33	**0.3661**	8.47	21550809	0.958	1.29
1	1590.11	2517.15	**0.3683**	7.93	21624680	0.961	1.58
1.5	1590.11	3023.26	**0.3753**	6.17	21868605	0.972	1.90
1.8	1590.11	3382.94	**0.3851**	3.72	22217263	0.987	2.13
3	1590.11	5250.79	**0.4342**	8.55	24143456	1.073	3.30
4	1590.11	7322.88	**0.4740**	18.51	25973018	1.154	4.61

Strongly Oil-Wet Dist.3 (SOR= 0.5)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	612.78	845.28	**0.4314**	7.86
1	612.78	1077.78	**0.4314**	7.86
1.5	612.78	1310.28	**0.4314**	7.86
1.8	612.78	1447.78	**0.4309**	7.71
3	487.78	1827.78	**0.4780**	19.50
4	487.78	2277.78	**0.4785**	19.62

Table 4.39: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.5, Distribution 3).

Strongly Oil-Wet Dist.4 (SOR= 0.5)					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Error (%)	Deviation (%)
976.53	1407.78	0.5	**0.4690**	1.49	6.20
976.53	1840.28	1	**0.4694**	0.45	6.13
976.53	2271.53	1.5	**0.4692**	0.32	6.15
987.78	2547.78	1.8	**0.4673**	0.28	6.53
987.78	3582.78	3	**0.4669**	0.19	6.63
987.78	4445.28	4	**0.4667**	0.16	6.66

Strongly Oil-Wet Dist.4 (SOR= 0.5)				
cons. $t_{50\%}$	part. $t_{50\%}$	k_d	Predicted S_o	Deviation (%)
1118.16	1606.12	0.5	**0.4660**	6.79
1118.16	2094.28	1	**0.4661**	6.78
1118.16	2589.68	1.5	**0.4673**	6.53
1118.16	2882.57	1.8	**0.4671**	6.57
1118.16	4054.42	3	**0.4668**	6.65
1118.16	4506.78	4	**0.4311**	13.79

Strongly Oil-Wet Dist.4 (SOR= 0.5)							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	1328.12	1901.95	**0.4636**	7.29	21269304	0.945	1.43
1	1328.12	2482.85	**0.4651**	6.98	21330050	0.948	1.87
1.5	1328.12	3115.47	**0.4729**	5.42	21646487	0.962	2.35
1.8	1328.12	3579.61	**0.4850**	3.00	22155616	0.985	2.70
3	1328.12	6156.24	**0.5479**	9.57	25235863	1.122	4.64
4	1328.12	8455.42	**0.5729**	14.59	26717396	1.187	6.37

Strongly Oil-Wet Dist.4 (SOR= 0.5)				
	T_{bt}		So	Deviation (%)
k_d	cons.	part.		
0.5	482.78	772.78	**0.5457**	9.15
1	482.78	1060.28	**0.5447**	8.93
1.5	482.78	1350.28	**0.5450**	9.00
1.8	482.78	1525.28	**0.5454**	9.08
3	372.78	2037.78	**0.5982**	19.64
4	372.78	2607.78	**0.5998**	19.96

Table 4.40: Numerical results from mode time, $t_{50\%}$, breakthrough and MRT in the strongly oil-wet system (S_{OR}= 0.5, Distribution 4).

2D model	
No. of blocks in x direction	100
No. of blocks in y direction	20
No. of blocks in z direction	1
D_x (per block)	100 ft.
D_y (per block)	50 ft.
D_z (per block)	90 ft.
Reservoir depth	8000 ft.
porosity (constant)	0.25
X permeability	1000 mD
Y permeability	1000 mD
Z permeability	100 mD
water saturation (average)	0.75
Residual Oil Saturation (S_{or})	0.6
oil density	49 ppg
water density	63 ppg
oil viscosity	1 Cp (@ Pres)
water viscosity	0.8 cP
water compressiblity	3E-06 1/psi
rock compressibility	4E-06 1/psi
B_w	1.02
reservoir pressure	4500 psi
Production rate	1500 stb/day
Injection rate	1500 stb/day
wellbore radius	4 inches

Table 4.41: Set of input data for Eclipse and UTCHEM comparison.

k_d	UTCHEM	ECLIPSE	Sor		Deviation %	
	t_{mode}		UTCHEM	ECLIPSE	utchem	eclipse
0	1508.046	1522.782				
0.5	1761.46	1743.282	**0.2515**	**0.2246**	0.62	10.17
1	2012.096	1960.282	**0.2505**	**0.2232**	0.20	10.73
1.5	2263.137	2180.782	**0.2503**	**0.2236**	0.11	10.54
2	2515.162	2404.782	**0.2503**	**0.2246**	0.13	10.17

Table 4.42: S_{OR} predictions through mode time utilisation in the uniform distribution.

k_d	UTCHEM	ECLIPSE	Sor		Deviation %	
	t_{mode}		UTCHEM	ECLIPSE	utchem	eclipse
0	1536.013	1550.782				
0.5	1775.017	1764.282	**0.2373**	**0.2291**	5.06	8.35
1	2009.049	1967.282	**0.2355**	**0.2192**	5.82	12.31
1.5	2235.026	2166.782	**0.2328**	**0.2149**	6.89	14.03
2	2460.036	2285.782	**0.2312**	**0.1962**	7.51	21.53

Table 4.43: S_{OR} predictions through mode time utilisation in the uniform Distribution 2.1.

k_d	UTCHEM	ECLIPSE	Sor		Deviation %	
	t_{mode}		UTCHEM	ECLIPSE	utchem	eclipse
0	1465.008	1477.282				
0.5	1737.000	1736.282	**0.2708**	**0.2703**	8.31	8.10
1	1989.000	1963.782	**0.2634**	**0.2540**	5.38	1.59
1.5	2227.000	2177.282	**0.2575**	**0.2448**	2.99	2.09
2	2462.000	2289.282	**0.2539**	**0.2196**	1.55	12.18

Table 4.44: S_{OR} predictions through mode time utilisation in the Distribution 2.2.

k_d	UTCHEM	ECLIPSE	Sor		Deviation %	
	t_{mode}		UTCHEM	ECLIPSE	utchem	eclipse
0	1486.256	1505.282				
0.5	1751	1729.282	**0.2627**	**0.2464**	5.07	1.42
1	2012	1956.782	**0.2613**	**0.2405**	4.52	3.82
1.5	2276	2191.282	**0.2616**	**0.2403**	4.63	3.90
2	2528	2429.282	**0.2595**	**0.2408**	3.80	3.66

Table 4.45: S_{OR} predictions through mode time utilisation in the Distribution 2.3.

5. Mobile Oil Study

This chapter is dedicated to cases where oil saturation is above its irreducible value. Apart from a homogeneous reservoir, heterogeneous cases where also examined. In terms of the latter, a 3D grid was implemented for the first time. If oil saturation is greater than its residual value the time at which tracer injection takes place is of importance. Oil saturation constantly decreases by virtue of water injection and therefore, injection at different times will yield different results as far as numerical techniques are concerned.

The numerical techniques that were used in irreducible oil cases, are not in reality valid if oil is mobile, which is clear from their derivations. Their accuracy as rough approximations is subsequently examined in this chapter.

A principal problem rises with respect to oil saturation predictions. In residual oil models the total simulation time is irrelevant with the obtained predictions, in the sense of that even if the latter was prolonged in comparison with the tracer-test period, oil saturation does not fluctuate. Thus, even if all injected tracers are produced at time X, simulation time prolonged at time X+A would not differentiate the numerical results exactly due to the fact that oil saturation is constant throughout he injection period. However, this is not the case when oil production occurs.

In fact, the actual problem is that it is not clear which is the very value that is predicted. Let us assume that an average oil saturation value is obtained. Clearly, the first moment is the initialisation of tracer injection. The final moment should be selected as t_f which is the final moment of each particular partitioning tracer. Hence, for different partition coefficient values naturally, t_f times will be different, and consequently, the obtained predictions will be compared with different average saturations. However, the final moment and the breakthrough time are susceptible to numerical diffusion. Hence, as far as the mode-time predictions are concerned an average of the saturation values that occur at the responding mode times (of the passive and the conservative tracer) will be employed. Apart from diffusion effects it is logical to employ these values, as they are the same that are utilised in the calculation of S_o. Concerning, mean residence time calculation however, those values cannot be used. For the calculations of the latter, the whole area needs to be computed, from the first day of injection until the final moment of the test. Hence, the saturations that occur at the final moment of the test have to be taken into account.

Two wettability systems were used; an oil-wet and a water-wet one. Their relative permeability versus saturation curves are presented in **Fig. 5.1** and **5.2**.

Both wells are surface- flowrate controlled for all cases. Oil exhibits a saturation value higher than its irreducible value. Previously in the velocity calculations only the denominator (cross sectional area) was changing whereas now the denominator (flowrate) is changing as well since the fractional flow of oil and water varies throughout the injection.

$$u_{water} = \frac{Q^{s.c} * B_w * f_w}{A * \varphi * (1 - S_{wc})}$$

Hence, even if the wells were controlled via reservoir conditions it would not ensure constant velocity in any case. Accordingly, the realistic scenario of surface flow rates control was selected.

5.1. Homogeneous Reservoir Cases

Reservoir and well properties being used in the homogeneous reservoir cases are illustrated in **Table 5.1**. For both wettability systems as far as mode time is concerned tracers are injected at three distinct moments: at day 1, 878 and 1755 with slug duration of one day. Similarly, the various injection slugs in terms of mean residence time calculations are: day 1, 600, 1000, 3000. Several initial oil saturation values were used. The reason is that in this way different production periods are depicted. With regards to both oil-wet and water-wet cases the initial oil saturation is either 0.75 or 0.5.

Since tracers are injected at various time steps it should be examined if they are affected among each other. For instance, if before the 2nd slug time (day 878) tracers that were injected at day 1 still flow in the reservoir this will have an impact above the implementation of numerical methods. This can be addressed by deconvolution filters with respect to injection time. In a simulator this can be easily attained simple by examining each slug period with a different run; totally 3 distinct runs for the 3 injection periods. Deconvolution filters were applied however, besides injection time correlation. Their results are presented in ***subchapter 5.4.***

The conservative and partitioning tracer (K_d= 0.5) responses are presented in **Fig. 5.3-5.5**. Three peaks can be seen, each one of them corresponding to the different tracer injection time. These should be examined in association with S_o versus time plots (**Fig. 5.6**). Apart from the first peak, the remaining two are identical even if the initial oil saturations at the beginning were different. However, after 800 days of injection the remaining average S_o is the same for both initial oil saturations. Hence, water velocities are the same leading to identical tracer responses for both conservative and partitioning tracers. The retardation of the latter is the same by virtue of the same quantity of oil that they are in contact with. The only differentiation lies in the first days of the test (1^{st} peak). Water velocity is initially small due to the high oil fraction (f_o close to 1) in terms of the 0.75 initial oil saturation. Oil production rate is high enough at the beginning but reduces abruptly and water velocity is constantly increasing, so that at the time that corresponds to the peak-concentration remaining average oil saturation and f_w are similar, and therefore water velocity is the same for both cases. Consequently, mode times exhibit relatively small variations.

Concerning oil-wet cases, the variations for the different initial saturations are more pronounced. Oil is not so easily produced due to the unfavourable wettability of the system. For initial oil concentrations of 0.75 and 0.5, the former will exhibit higher oil mobility for a much more increased amount of time. Oil saturation versus time and tracer concentration plots are presented in **Fig. 5.7-5.9** By virtue of the unfavourable oil wettability, conservative tracer exhibits higher velocity and yields an earlier breakthrough. If oil saturation was at its residual value the partitioning tracer response would be expected to be delayed in the case of the higher initial oil concentration. Yet, oil is mobile and due to the increased oil fractional flow (f_o close to 1 at the beginning) it exhibits an increased velocity. Hence, an earlier partitioning breakthrough occurs for higher initial oil saturation. At late times due to the reduction of oil fractional flow and the corresponding increase of water (f_w close to1) partitioning tracer responses are closer. Those effects fade as the test is repeated at later times and oil saturation reduces due to production, but they are visible even in the 3^{rd} peak. The effect is exactly the same for both wettability systems but in the water-wet system it is more opaque due to the abrupt oil production at early times.

If the tracers' concentration over time charts (**Fig. 5.11** and **5.12**) are examined the effect of dispersion is apparent. A comparison among the latter and the oil saturation versus time chart (**Fig. 5.10**) for the entire grid may give useful information about the flow pattern of tracers. Conservative tracer lives at the front of the injected water whereas partitioning tracers live at the back of the front. The lower the partitioning coefficient the more advanced the position of the tracer will be –but always well behind the non-partitioning one- and vice versa. Therefore, exactly at the moment of water breakthrough the breakthrough of the conservative tracer occurs, while the partitioning ones are behind; how much, depending on their partition coefficient value.

In terms of predictions obtained from mode-time use, the results are fairly accurate (**Tables 5.2-5.5**). Naturally, the greater the initial oil saturation value the higher the deviations from the average saturations. Particularly, in the water-wet model where flow of oil is facilitated from high relative permeability values, early at the injection period oil saturation varies dramatically, effecting the generated predictions this way. The time at which tracer injection takes place is of importance, not least for high initial oil saturation cases. The later tracer injection period begins, the more oil will have been produced so that at the actual time of testing saturation variations will be of lower magnitude. Once again predictions from mean residence time use yield more accurate results (**Tables 5.6-5.9**). Although, the very values that predictions from mode time and mean residence time are compared to, are actually different, the fact that in mean residence time the whole testing period is taken into account is advantageous in order to captivate the full range of saturation variations. Contrariwise, in mode time calculations only the peak-times are utilised, so that any changes beyond the t_{mode} of the partitioning tracer are not accounted. Mean Residence Time calculations according to Akasawa (2005) were implemented as well but their results for those cases underestimated the remaining oil saturations.

5.2 Viscosity Effect

In every case study, water flooding takes place which is accompanied by a slug tracer injection. Fluids' viscosity is a key factor in terms of water flooding success and since all data are synthetic it is important to determine the effect of viscosity in the obtained results.

Generally, mobility ratios that favour oil flow are desired in water injection studies. For a piston-like displacement and an efficient water flooding process with high oil recovery high water viscosity and low oil one are beneficial (Ahmed, 2005). In real problems oil viscosity is given from PVT data and for that specific value the water injection process is designed. Since all data are synthetic, both water and oil viscosity should be examined. By utilising exactly the same data of the water-wet model, four cases will be modelled:

- Case 1: Denotes the water wet model used in the homogenous reservoir study.
- Case 2: Same data as before, apart water viscosity that exhibits a greater value (1 cP instead of 0.8 cP).
- Case 3: Same data set with case 1 but with lower oil viscosity.
- Case 4: Same data set with case 1, but use of water viscosity from case 1 and oil viscosity from case 3.

The corresponding conservative and partitioning (k_d= 1) tracer responses are presented in **Fig. 5.13** and **Fig. 5.14**. Higher water viscosity and lower oil viscosity lead to a more piston-like displacement and delay of water breakthrough. If the favourable oil and water viscosities are combined they yield an even later breakthrough compared to the separate use of each one. Average oil recovery is enhanced and phenomena such as oil fingers bypassed by water due to high oil viscosity are avoided. Due to the smaller water velocity and the later breakthrough, diffusion effect is greater so that the peak concentrations are smaller for lower oil viscosity and greater water one. At the same time, partitioning tracer indicate a similar response yet with smaller variations. With regards to the numerical methods, it is clear from the used formulations that the obtained predictions would underestimate S_o. From the tables where the numerical results are presented it can be deduced that the predictions do underestimate the average oil saturation. Hence, if such viscosities were used that amplify this phenomenon worst results would be naturally obtained.

Relative permeability values of oil are greater in a water-wet reservoir than an oil-wet one, and for given oil and water viscosity, mobility ratio favours oil flow in the former case (water-wet reservoir).

5.3. Heterogeneous Reservoir Cases

Two distinct heterogeneous reservoirs were modelled (**Fig. 5.15- 5.16**): a three-layer 600x600x60 ft^3 reservoir with permeability values from top to bottom layer (k_{1x}=$k_{1y=}$ 400 mD, k_{1z}= 40 mD), (k_{2x}=$k_{2y=}$ 1000 mD, k_{2z}= 100 mD), (k_{3x}=$k_{3y=}$ 600 mD, k_{1z}= 60 mD) and a reservoir of 600x600x40 ft^3 that contains a high permeable thief zone (of 1 ft. thickness). Thief zone permeability values are (k_x=k_y=1000 mD, k_z=100 mD), whereas the rest of the matrix exhibits constant permeability of (k_x=k_y=100 mD, k_z=10 mD). The two wettability systems utilised in the homogeneous cases were also implemented here, for various initial oil saturation values. Reservoir properties are exactly the same as in the homogeneous case studies apart from the flowrate in which a constant value of 1000 stb/day was selected for both the injector and the producer (Q_{inj} = Q_{prod} = 1000 stb/day).

Tracer slugs are injected at several time intervals; day 1, 100, 300, 600, and 1000. Grid definition was attained as usually. Since absolute permeability values are not constant spatial discretisation along the z axis is necessary. A common discretisation technique for such type of reservoirs in order to save up computational time is to discretise only along x and z directions. Three completions per well were used (one in each layer) and water injection as well as tracer slugs are implemented simultaneously for all completions. It goes without saying, that this is not the optimal production scheme. Injection in a layer of high permeability would be naturally delayed for oil recovery maximisation. Since, tracer response is sought rather than an optimal production configuration this is not a problem. Five tracers are injected as slugs at various time intervals: a conservative tracer alongside four partitioning tracers (k_d= 0.5, 1, 1.5 and 2) in all 3 completions. Initially, all five tracers are injected simultaneously at all completions and either their average (field) concertation can be reported or the concentration observed per connection.

5.3.1 Three-layer Reservoir

Tracer responses for the various injection periods for both wettability systems are illustrated in **Fig. 5.17- 5.21**. Tracer responses are presented in each one of the three connections as well as the average value between all three connections. Tracer breakthrough naturally occurs first in the high permeable zone and it is more delayed in the zone that exhibits the smaller absolute permeability value. The shape of the generated curves indicates some irregularities. For instance, in the conservative tracer response of the water-wet system for the topmost (**Fig. 5.17-** *top left*) it seems that the response of the 1st slug is of a tracer with different mass than that of the other slugs. Apart from the higher value of maximum concentration (which can be an effect of molecular diffusion) it is obvious that the area of this curve is many times greater than all others'. The injected quantities for all tracers are the same and so does the slug duration. This phenomenon is related to crossflow between the layers. Since, greater mass of a particular tracer appears in a layer than it was not meant to it is expected that in another layer (the one that the tracer was originally injected) smaller quantity of this tracer will occur. The same tracer response in the high permeable 2nd layer (**Fig. 5.17-** *top right*) corroborates this fact. There, the mass of the 1st slug appears significantly lower compared to all other slugs. Therefore, crossflow between layers 1 and 2 can be deduced. Crossflow phenomena are more apparent when oil saturation is higher and over time they seem to fade. If a uniform absolute permeability value of 0 across the z axis is implemented the effect of crossflow among the layers can be realised (**Fig. 5.24**).

Any attempt to quantify crossflow through numerical methods would inevitably yield results pretty much wide of the mark. The injection scheme has to be modified in order to attain the latter. Instead of injecting the same tracers in all layers, let us use a unique tracer for each layer. In that fashion the conservative tracer would be different for each particular layer. Hence, different tracers will be injected in each layer at each slug period. For 3 layers and 5 totally tracers (one conservative and four partitioning), 15 tracers are going to be injected at each slug period; for 5 slug periods 75 exactly different tracers will be used in a single experiment. In a simulator this is feasible simply be changing the name of the tracer for each layer and time interval. In a real experiment however this would have been a tedious if feasible at all process.

Figs. 5.24 and **5.26** depict the concentration of each tracer in the very layer that was intended to flow. If these responses are compared once again with the average (field) concentrations of each tracer (**Figs. 5.25 and 5.27**) the occurrence of crossflow is apparent. In order to fully determine the relative crossflow patterns among the layers of the reservoir the concentration curves of each particular tracer for all connections are illustrated in **Fig. 5.28** (Conservative tracer originally injected at layer 1), **Fig. 5.29** (Conservative tracer originally injected at layer 2) and **Fig. 5.30** (Conservative tracer originally injected at layer 3).

It can be inferred that crossflow takes place between all three layers, but it is more profound among the top two layers. At this point it should be determined whether interflow between the layers occurs or if the relative crossflow takes place across the z axis at the wellbore blocks. The latter is descripted as a commingled system (*Park, 1989*). If cross section plots (over the z axis) are generated with regards to the contextual tracer concentrations (**Figs. 5.31- 5.36**) for the entire grid it can be concluded that interflow between the layers happens than commingled flow.

It has been already pointed out that interwell tracer analysis is important for the determination of flow regimes. From a cross section that depicts oil saturation variations due to production (**Figs. 5.37-5.38**) the occurrence of crossflow cannot be realised.

The reason of the crossflow among the layers should be examined more meticulously. The chief cause for inflow among the layers is the difference in layers' permeabilities which results in pressure differences as well. Thus, a high permeable zone produces oil faster which leads to a sharper pressure drop. Hence, oil from the least permeable zones could flow in the high permeable zone due to this favourable pressure difference. However this is not the case here. Chiefly, crossflow takes place from the high permeable zones into the lower ones.

Zapata and Lake (1981) developed a model in order to investigate viscous crossflow. The latter is the crossflow that stems from the difference between oil and water in a water flooding scheme. The key idea, is the one described before; the difference in permeability leads to different advance of the front in each layer, so that in a higher permeable layer water which is far behind oil can be in contact vertically with oil from the low permeable ones. According to their theory, the ratio of oil and water mobility should be investigated. When $M<1$ crossflow will occur from the low permeable layer to the higher one at the front (oil into the high permeable zone and water into the lower permeable one), whereas the opposite will happen at the trailing front. In case $M>1$, flow will take place at the opposite order. That is, at the leading front, water will flow from the high permeable zone to the lower one, whilst oil will flow into the high permeable zone. An extended mixed zone is generated in that fashion rendering things a bit vague. The first case ($M<1$) is favourable in terms of production whereas the second will unavoidably lead to unexploited oil due to trapped oil sockets by opposing capillary forces.

In order to determine the initiates of crossflow let us consider the following production scheme: in exactly the same reservoir, topmost and bottommost lower-permeable layers have undergone production and they exhibit a residual saturation values, while the middle high-permeable layer exhibits a saturation value close to the connate one. In such a system one would expect that oil would be normally only produced from the middle layer, since the other two contain residual oil. The cumulative oil production for each layer over time is presented in **Fig. 5.39**. A descent amount of oil seems to be produced from the topmost layer. In order to mobilise residual oil, EOR methods ought to be applied. The answer is that the oil that is produced from layer 1 originates from the middle layer. From **Fig. 5.40** which represents oil saturation over time for each layer, it can be seen that after one day of injection oil from the middle layer ascends to the topmost one. Due to the positive z-permeability values and the subsequent positive transmissibility across the z axis, part of water that is originally being injected at the top layer flows downwards to the middle layer. As a consequence, this excess of water displaces oil upwards to the top layer so that oil appears to be produced from that layer. By setting all z-permeability values at zero (or transmissibility values along the z-axis, which is scientifically more appropriate), the produced barrels of oil would originate solely from the middle layer. Simultaneously, tracer responses would have been affected by crossflow. In terms of the topmost layer, the 'migrated' oil would delay both conservative and partitioning tracer responses, leading to overestimated predictions in terms of S_o. With regards to the middle layer, tracer flow would have been faster for both conservative and partitioning tracer, thus underestimating S_o.

As far the numerical techniques are concerned, since their application to cases where oil exhibits a saturation higher than its residual value, only mean residence time predictions will be investigated. For a different reason than before, the main problem is the very value that the generated predictions (per layer this time) will be compared to. A simulator such as ECLIPSE gives an average oil saturation for the entire reservoir rather than each layer separately at each time step. To address this issue a simple volumetric estimation can be made with regards to Original Oil In Place (OOIP) for each layer. For 3 layers (k=3) that exhibit the same thickness:

$$OOIP_k\ (bbl) = V_{b)k} * \varphi * (1 - S_w)$$

$V_{b)k}$ is the corresponding bulk volume each particular layer. The produced barrels of oil observed at each connection will be utilised in association with the latter values in order to find the remaining oil saturation per layer.

$$(S_o)_k = \frac{OOIP_k - Prod.oil_k}{V_{b)k} \ * \varphi}$$

The denominator of the latter expression simply denotes the pore volume of each particular layer. The produced oil volumes at each connection correspond to the final moment (t_f) of the test or the final moment in the tracer response curve where a non-zero concentration is observed.

The S_o predictions based on mean residence time use were carried out in three ways. Firstly, tracer responses in cases where the same tracers are injected in each layer were utilised (**Tables 5.10-5.13**). Secondly, the corresponding concentrations of the tracers that were injected in each particular layer were employed as well (**Tables 5.14-5.17**). Finally, in order to compare the aforementioned results, tracer concentrations injected at each layer were used, yet this time with zero transmissibility along the z axis (**Tables 5.21-5.24**). In this way, the effect of interflow between the layers on predictions would be clearer. At the same time, production data were utilised and according to the volumetric calculations that have been described S_o calculations were accomplished. These calculations were conducted both in the real scenario of positive z-transmissibility (**Tables 5.18-5.20**) and the case of zero z-transmissibility as well (**Tables 5.25-5.28**).

Apparently, the results obtained from the first case (same tracers injected at all connections) are the most ambiguous, not least in terms of earlier times. At early times saturations vary rapidly due to production, which exacerbates the reliability of the results. Favourable wettability regarding oil and high initial oil saturation further deteriorate the predictions, so that the water-wet model of initial oil saturation 0.75 is the most problematic, whereas the oil-wet model of 0.65 S_{oi} illustrates relatively small variations over time. As far as the latter is concerned the implementation of the same test over time yields very similar results.

The modification of the injection scheme with the use of specific tracers for each layer is advantageous. Yet, the problem of crossflow that effects tracer responses and hence numerical results, is not tackled. For instance, in the water-wet system of S_{oi}= 0.75 for the day 1 slug injection (**Fig. 5.14-** *top left*), the middle high permeable layer is predicted to exhibit an oil saturation value well above its residual value. This does not align with reality and naturally the other two layers' predictions will exhibit similar irregularities by virtue of crossflow. This can be asserted when comparing the numerical results with those of zero z-transmissibility, where even during the first slug periods the generated predictions from mean residence time exhibit a realistic value; the high permeable layer exhibits a smaller remaining oil saturation, yet above its residual value, whereas the other two layers exhibit a higher oil saturation. For smaller initial oil saturation and particularly for a wettability system that favours aqueous phase flow instead of oil those effects are less apparent once again. When z-transmissibility exhibits a zero value throughout the reservoir, predictions from tracer responses as well as from production data do coincide independent of the wettability system and the initial saturation. From the homogeneous reservoir cases it has been already verified that fairly accurate predictions are obtained for mobile oil cases. The reason why they appear deteriorated in this case is crossflow that affects the velocity and retardation of tracers. When oil ascends from the middle layer to the topmost one, tracer flow in the former occurs faster due to the lost quantity of oil whereas in the latter the flow exhibits higher retardation by virtue of the surplus volume of oil.

Moreover, production data usage can lead to the same conclusions. By comparing the results with 0 z-transmissibility, it can be deduced that oil interflows from layer 2 towards layer 1 (primarily) and layer 3. The remaining saturation is found much greater in the middle zone whereas the other layers exhibit smaller remaining saturation, should vertical flow is prohibited. Of course those results are not totally accurate for many reasons. First of all, the final moment is selected as the last observed time value at which non-zero tracer concentration occurs, which is prone to numerical diffusion. Moreover, production data are reported in ECLIPSE in stb conditions. To convert them to reservoir conditions and calculate the remaining saturation from the volumetric expression an average oil formation volume factor is used, rather than its specific value at each pressure, in order to avoid tedious calculations.

At late times when sufficient amount of oil has been produced, numerical results tend to provide improved results. In fact this is the very period that tracers are meant to be used for reservoir characterisation; before the application of Enhanced Oil Recovery methods. At any rate, the injection scheme was not selected to provide maximum oil recovery. For instance, injecting water at a multilayer reservoir simultaneously at all layers would be unacceptable from both an engineering and economic point of view, due to the sufficient quantities of unrecovered oil. Tracers' purpose of identifying flow regimes is accomplished and the ensuing investigation will have to be focused on the optimal production configuration.

5.3.2. High permeable thief zone

As already descripted the thief zone reservoir contains a thin layer with thickness 40 times smaller than the total reservoir thickness and permeability 10 times greater than the rest of the reservoir. The wells are connected in all three layers. Subsequently, in the high permeable layer the generated velocities will be extremely high due to the small cross sectional area. The wettability systems used in the previous case as well as the slugs at day 1, 300 and 600. Were utilised for the thief zone reservoir. For each particular layer different tracers are being injected. The responses of conservative tracers in the water-wet system (S_{oi}= 0.75) are presented in **Figs. 5.41-5.43**, whereas the corresponding curves of the oil-wet system (S_{oi}= 0.65) are illustrated in **Figs. 5.44-5.46**.

Interflow phenomena between the layers of the reservoir occur, which can be deduced from the aforementioned curves. Once again they are more profound in the water-wet system, in which the flow of oil is facilitated, whereas in the oil-wet system the effects are limited.

Since, water injection takes place simultaneously in all layers, oil is produced faster from the high permeable zone (**Fig. 5.47**). Injection and production flowrates are surface controlled. For an equal production and injection flowrate in stb/day the volume of oil produced is greater than the injected water into the reservoir due to the higher value of oil formation volume factor than that of water, which is approximately 1. Since, fluid volume is reduced throughout productions pressure declines as well in the high permeable layer. Hence, a pressure difference across the z-axis occurs, so that fluids from top and bottom layer instead of flowing towards the wellbore flow across the high permeable layer. This can be asserted by utilising production data. As far as the day 1 slug, by using the volumetric S_o calculations (**Table 5.29**) the middle layer is supposed to exhibit a negative saturation. In fact it cannot exhibit a saturation smaller than its residual value. So this negative value implies that the oil produced from the connection of the 2nd layer is many times greater than the pore volume that corresponds to this very layer. Hence, oil that used to live in the topmost and bottommost layer was produced through layer 2. Although predictions from mean residence time exhibit different values in fact they comply with production data (**Table 5.30**). Tracer response is retarded in the thief zone due to the excess of oil that crossflowed from the other layers, and hence a high value of S_o is predicted in terms of the middle layer. Also, it can be inferred that a partition coefficient of 0.5 is too small and the corresponding retardation of partitioning tracer is not sufficient. Oil saturation predictions for the topmost and bottommost layer are smaller in terms of mean residence time calculations in comparison with the volumetric estimation. Since oil from these layers travels vertically to the middle layer, due to oil volume loss tracers' response is faster, and hence saturation predictions are smaller.

This can be asserted by setting zero transmissibility across the z direction (**Table 5.31** and **5.32**). Crossflow is prohibited and predictions from both mean residence time and production data generate similar results.

The same implications are valid with regards to the oil-wet system of 0.65 initial oil saturation. Due to the higher residual value of oil and the reduced values of oil relative permeability so that mobility ratio favours water, the effects are not that profound. However, a negative value is once again predicted as the middle layer's saturation from production data (**Table 5.33**), whilst an increased saturation is predicted from mean residence time (**Table 5.34**). Due to the small oil mobility, if the slug injections are repeated over time and a 0 z-transmissibility value is set, both predictions will produce identical results (**Tables 5.35** and **5.36**), as the fractional flow of oil is very small compared to that of water.

As far as the 'intermediate' cases –the water-wet reservoir of S_{oi}= 0.5 and the oil-wet reservoir of S_{oi}= 0.75- the generated predictions from both production data and mean residence time are illustrated in **Tables 5.37** and **5.38**.

In terms of the water-wet system, mean residence time predictions yield an increased value for the middle layer (due to the surplus oil volume) whereas the top and bottom layer exhibit a reduced value. The fact that normal predictions are obtained from volumetric calculations, which means lower remaining saturation in the high permeable zone and higher ones in the top and bottom layers, points towards that due to the reduced initial oil saturation, oil mobility is subsequently decreased (oil relative permeability and fractional flow of oil). Hence, oil flow and crossflow phenomena are limited in this case.

5.4. Smoothing and Deconvolution Filters

Apart from field applications where the signalled tracer responses usually exert some noise, concentration responses that exhibit unphysical shapes may be obtained from a simulator as well. As already explained ECLIPSE solves by default the concentration equations of tracer in each cell by a linear convection equation. In order to address numerical diffusion the possibility of a number of 2nd order flux limiting schemes is offered, where the equations are used either fully implicitly or fully explicitly (*ECLIPSE Technical Description*). In terms of the smooth parts of concentration solution a second order accuracy scheme is used whereas near sharp fronts a first order scheme is employed.

In **Fig. 5.48** the concentration curves of a conservative tracer are depicted, for a first order scheme, two different second order ones, of the same time step value (18 days). Apart from the first order scheme all others exhibit abnormal oscillations, which are greater in terms of the Van Leer flux limiting scheme than Minmod one which more diffusive. Those second order flux limiting schemes are supposed to result in non-physical effects for high time steps (*ECLIPSE Reference Manual*). If the time step size is reduced, apart from the alleviation of diffusion, the irregularities exhibit smaller magnitude (**Fig. 5.49**). For a given reservoir size and tracer velocity there is a limitation towards the smallest time step that can be employed in order to identify maximum concentration times and other figures. In order to verify the suggestion than second order flux limiting schemes are efficient with small time steps, the same model as before will be conducted, yet with smaller reservoir size (over the x and z directions). Thereby, a much smaller time step can be utilised, that still encaptivates the desired phenomena (tracer response). For small enough time steps it can be inferred that higher order schemes are adequate and do not yield unphysical responses (**Fig. 5.50**). The latter appears more sharpened due to the smaller distance between the injector and the producer and thus, the reduced effect of molecular diffusion.

Notwithstanding, reservoir size is given and cannot be modified to enhance the simulation results. Therefore, there is a minimum time step size according to which all subsequent runs can be conducted. If its value is relatively high (due to great distance between the wells and/or small velocity) it may not be sufficient to provide accurate results with higher-order schemes. One way is to degrade the order of accuracy. However, diffusion is broad and eventually the results may not be as precise as they would be intended to. The other way is to apply such techniques that can smoothen the concentration values, so that diffusion is adequately tackled.

Over the years several filters and techniques have been devised that can be utilised, either in a spreadsheet or directly in software. In this case, smoothing filters were applied as well as curve fitting that depends on mean square minimisation, in the **ORIGIN PRO 2018** software developed by ***OriginLab***. In terms of smoothing, each point is replaced by the average of a number (that is selected by the user himself) points which are located in the vicinity of the former (weighted or not) (O' Haver, 2018). What is more, curve fitting (Gauss-type, or Voight) may be applied in which the sum of squares of the y-axis points are minimised rather than the y-axis values themselves. Deconvolved data by virtue of the aforementioned techniques are illustrated in **Figs. 5.51- 5.54**.

By processing the concentration curves that exhibit irregularities a sharp response is obtained, in which diffusion is limited. If a first order scheme is used instead, further processing of the curves will be not required but diffusion effect will be broader.

Figures of Chapter 5

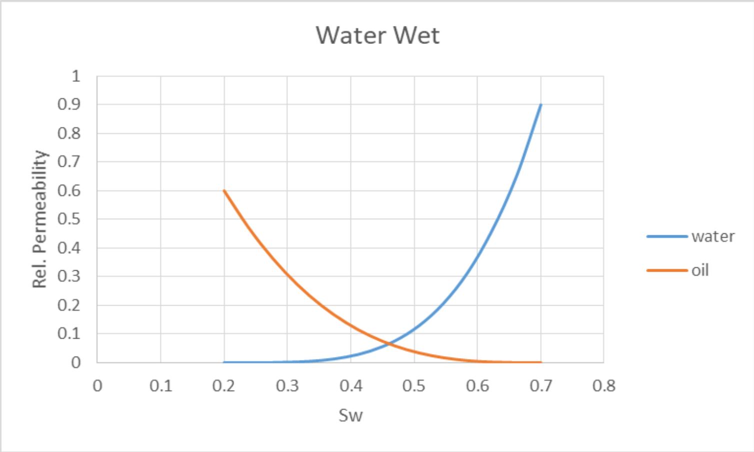

Figure 5.1: Relative permeability curves of the water-wet system.

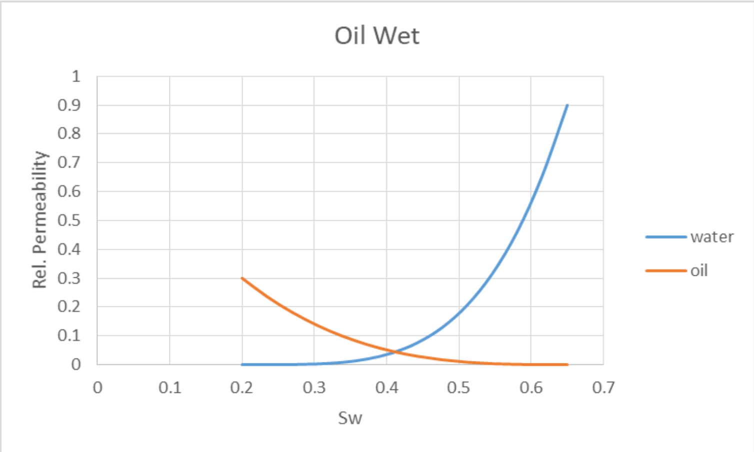

Figure 5.2: Relative permeability curves of the oil-wet system.

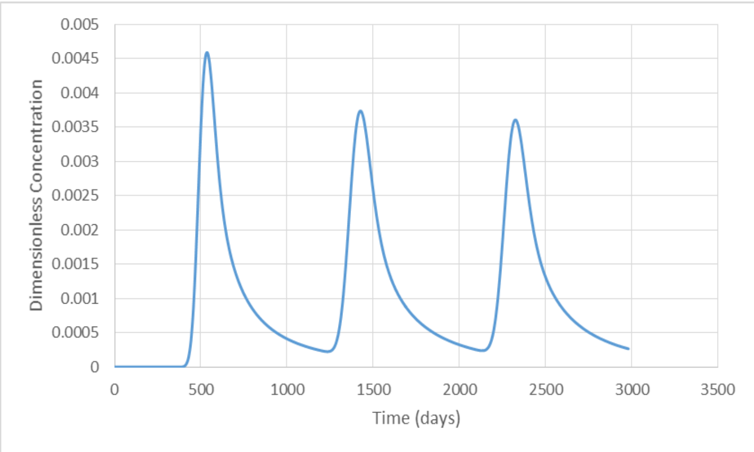

Figure 5.3: Conservative tracer response of the water-wet model (S_{oi}= 0.75).

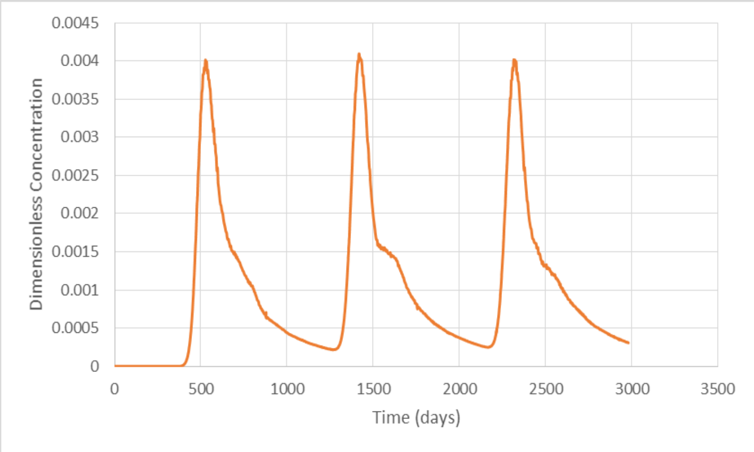

Figure 5.4: Conservative tracer response of the water-wet model (S_{oi}= 0.5).

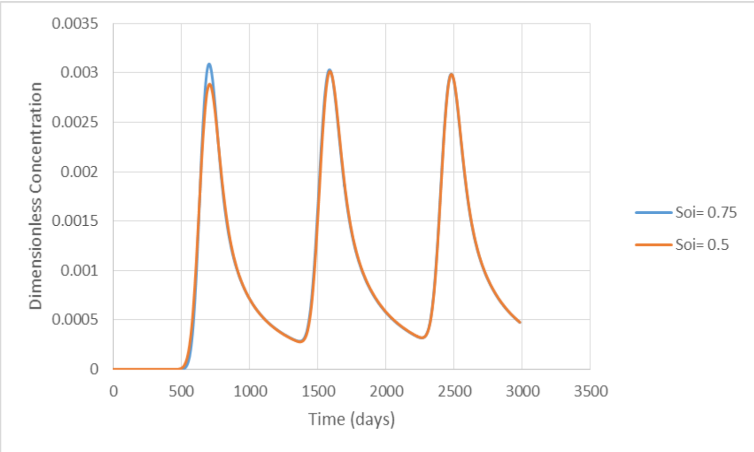

Figure 5.5: Partitioning tracer (K_d= 0.5) response of the water-wet model (S_{oi}= 0.5 and S_{oi}= 0.25).

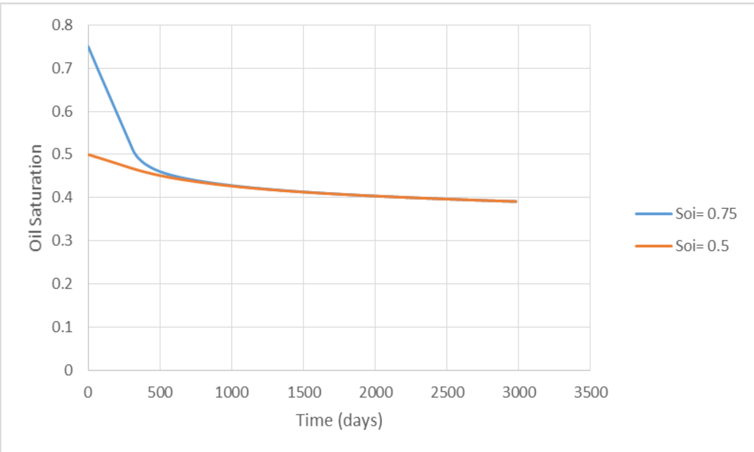

Figure 5.6: Average reservoir saturation of the water-wet model (S_{oi}= 0.5 and S_{oi}= 0.75).

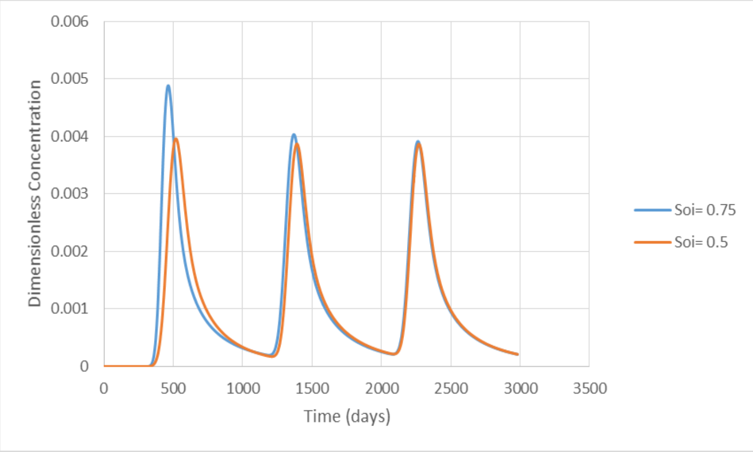

Figure 5.7: Conservative tracer response of the oil-wet model (S_{oi}= 0.5 and S_{oi}= 0.75).

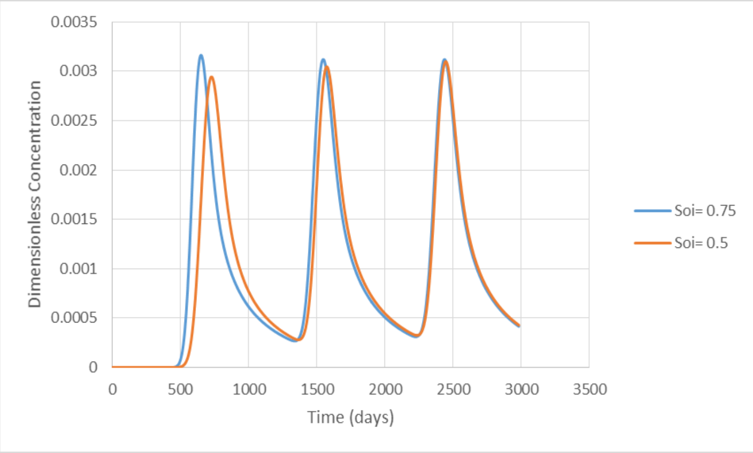

Figure 5.8: Partitioning tracer (K_d= 0.5) response of the oil-wet model (S_{oi}= 0.5 and S_{oi}= 0.75).

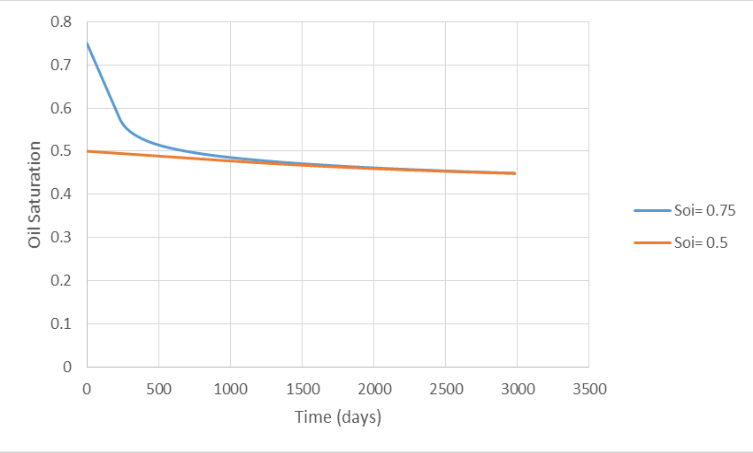

Figure 5.9: Average reservoir saturation of the oil-wet model (S_{oi}= 0.5 and S_{oi}= 0.75).

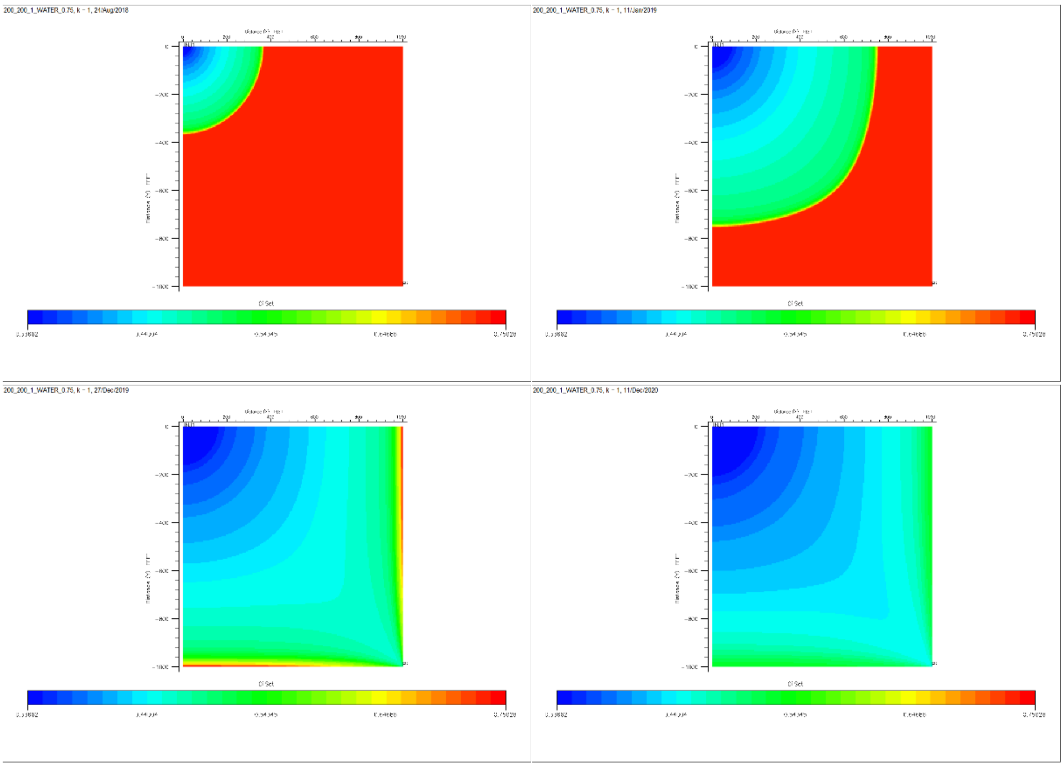

Figure 5.10: Oil saturation through time of the water-wet model (S_{oi}= 0.75).

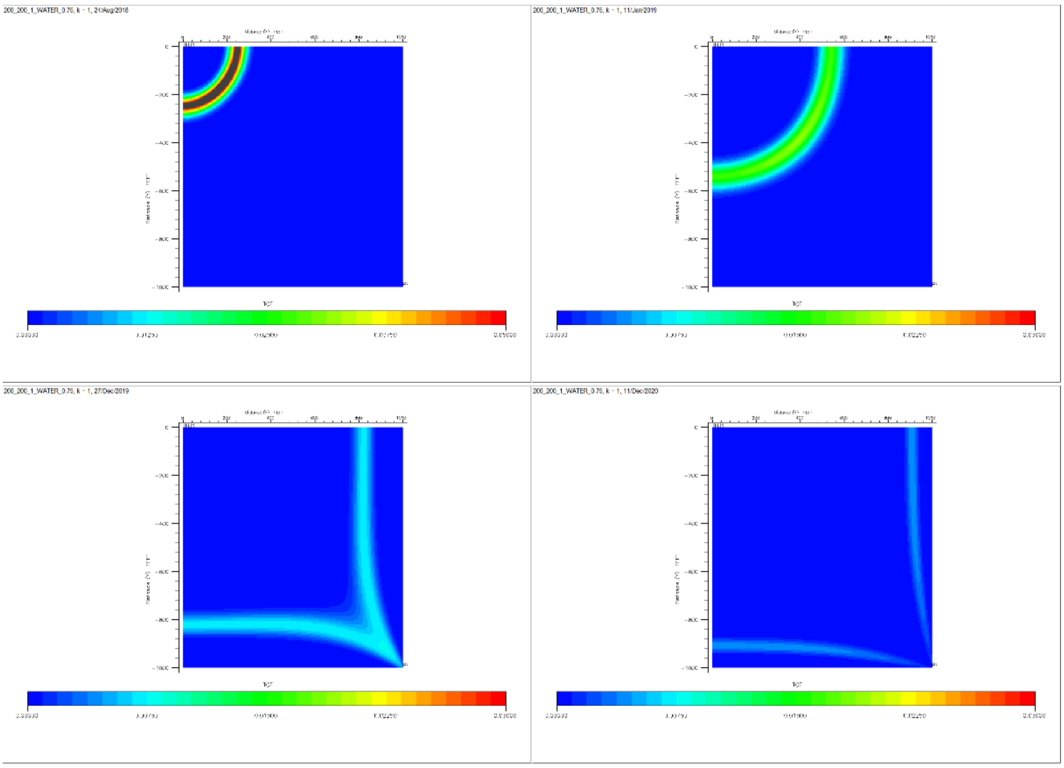

Figure 5.11: Conservative tracer concentration chart of the water-wet model (S_{oi}= 0.75).

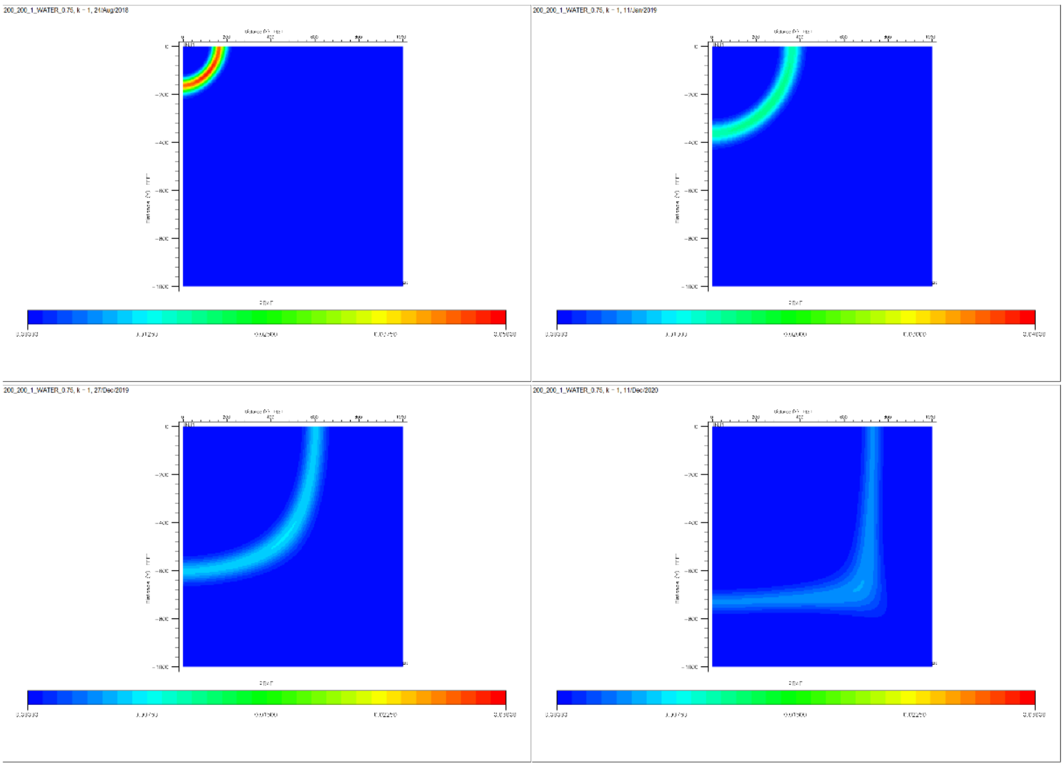

Figure 5.12: Partitioning tracer (k_d= 1.8) concentration chart of the water-wet model (S_{oi}= 0.75).

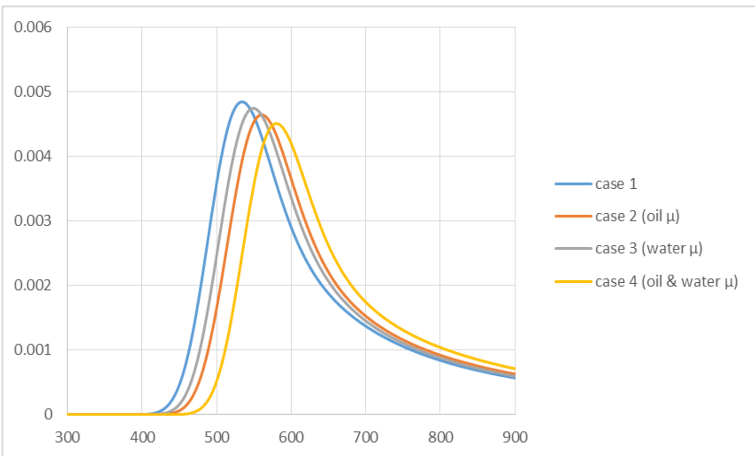

Figure 5.13: Conservative tracer responses for various oil and water viscosity values.

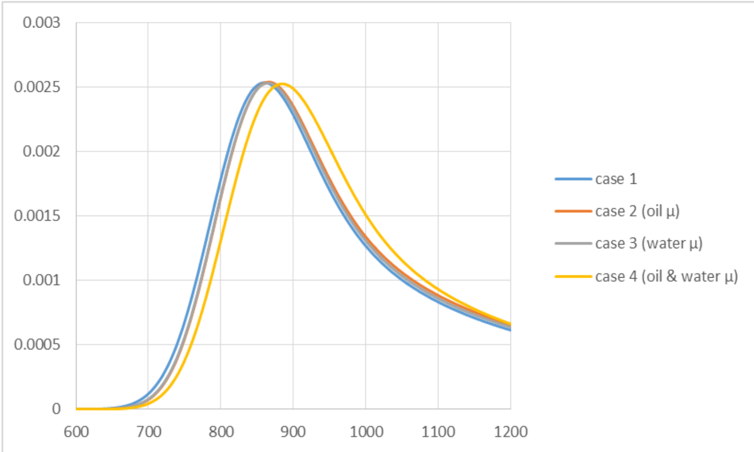

Figure 5.14: Partitioning tracer ($k_d = 1$) responses for various oil and water viscosity values.

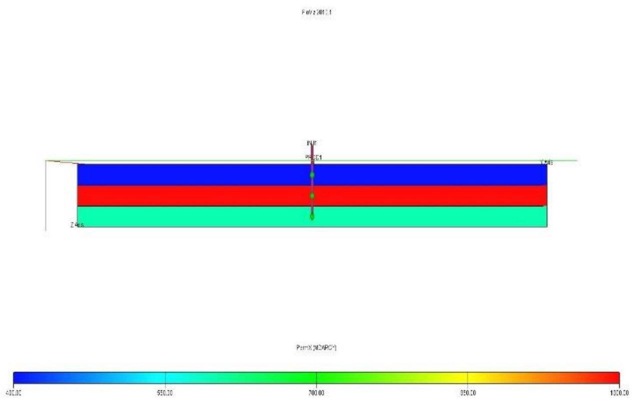

Figure 5.15: Permeability values along x-axis in the 3-layer heterogeneous model.

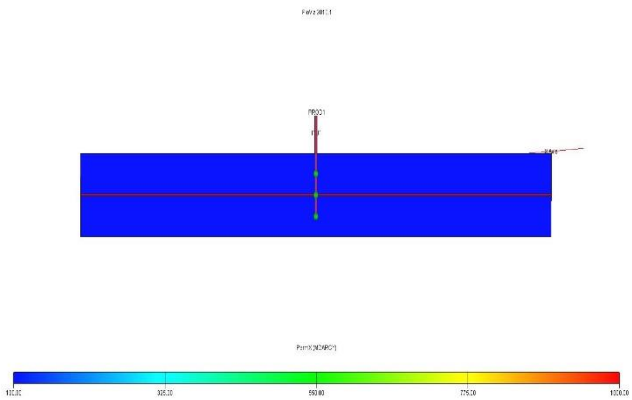

Figure 5.16: Permeability values along x-axis in the thief-zone heterogeneous model.

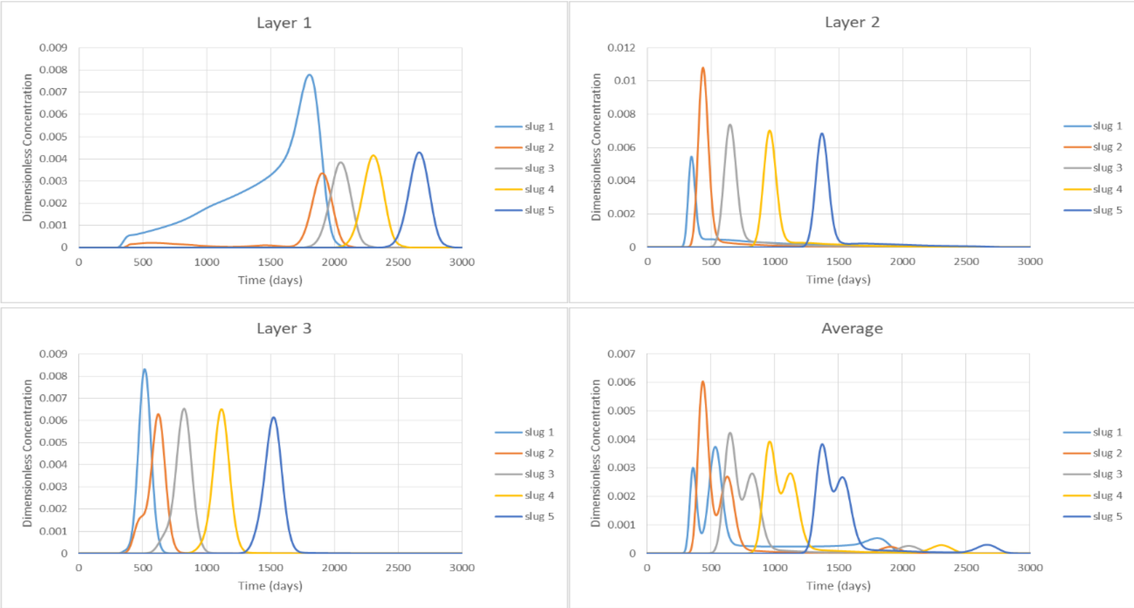

Figure 5.17: Conservative tracer response in all 3 connections and as average in the 3-layer water-wet system (S_{oi}= 0.75).

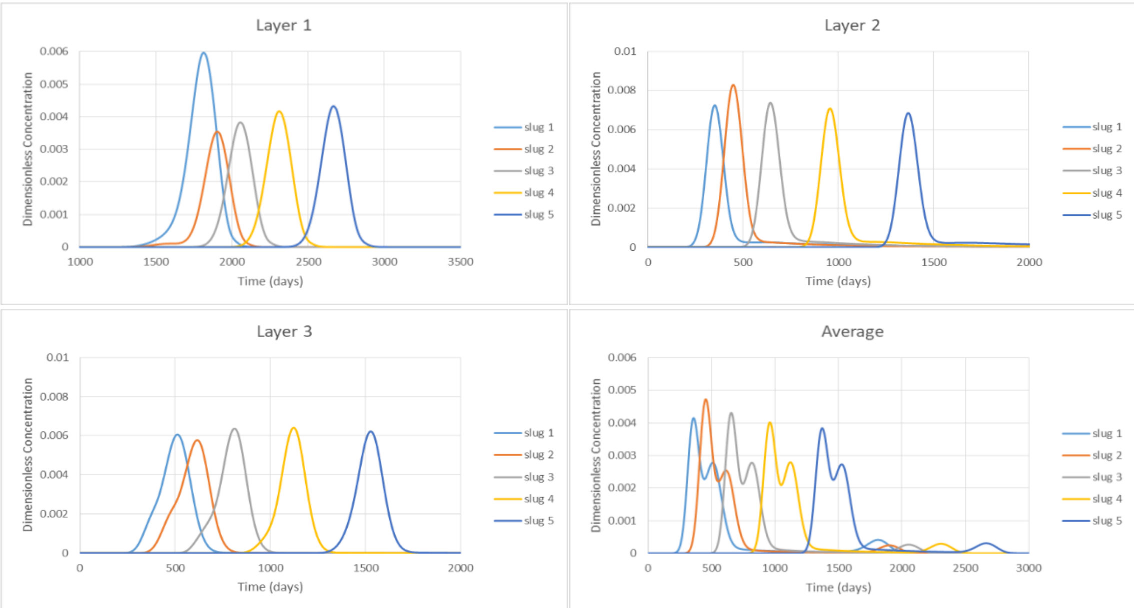

Figure 5.18: Conservative tracer response in all 3 connections and as average in the 3-layer water-wet system (S_{oi}= 0.5).

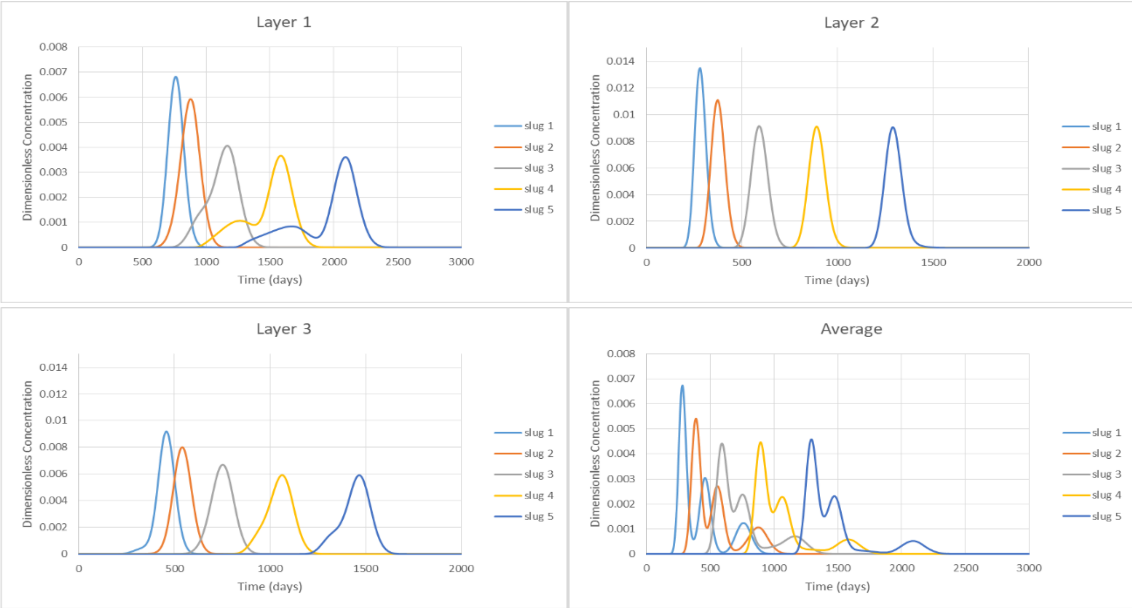

Figure 5.19: Conservative tracer response in all 3 connections and as average in the 3-layer oil-wet system (S_{oi}= 0.65).

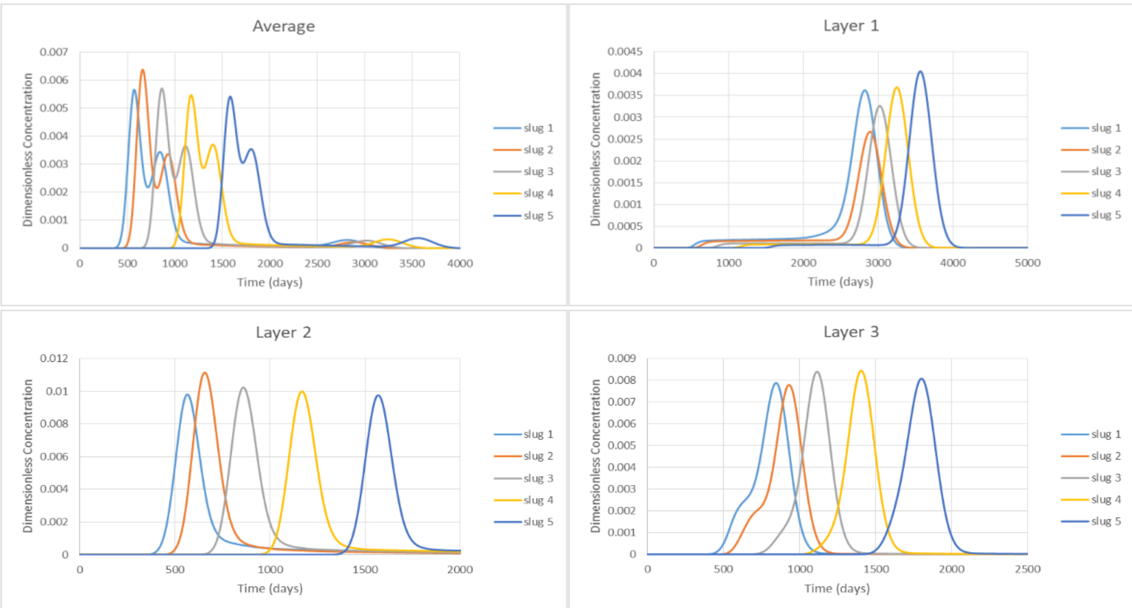

Figure 5.20: Partitioning tracer (k_d= 1) response in all 3 connections and as average in the 3-layer water-wet system (S_{oi}= 0.5).

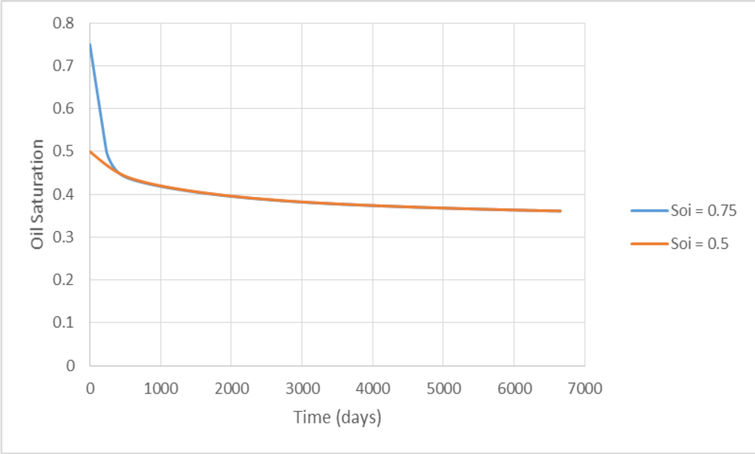

Figure 5.21: Average oil saturation over time in the 3-layer water-wet system (S_{oi}= 0.75 and 0.5).

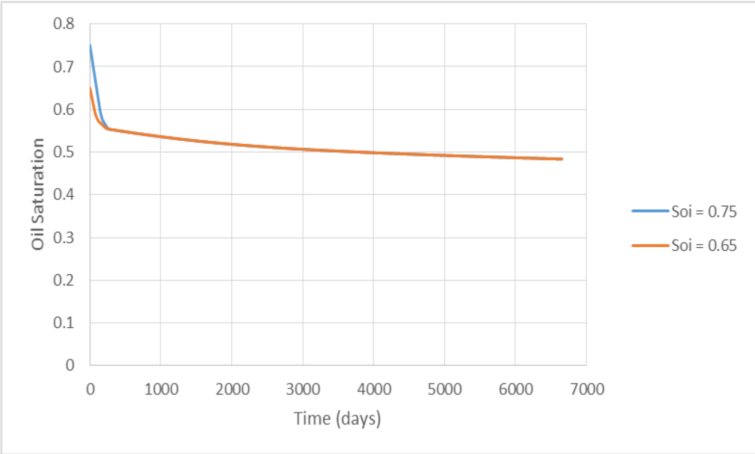

Figure 5.22: Average oil saturation over time in the 3-layer oil-wet system (S_{oi}= 0.75 and 0.65).

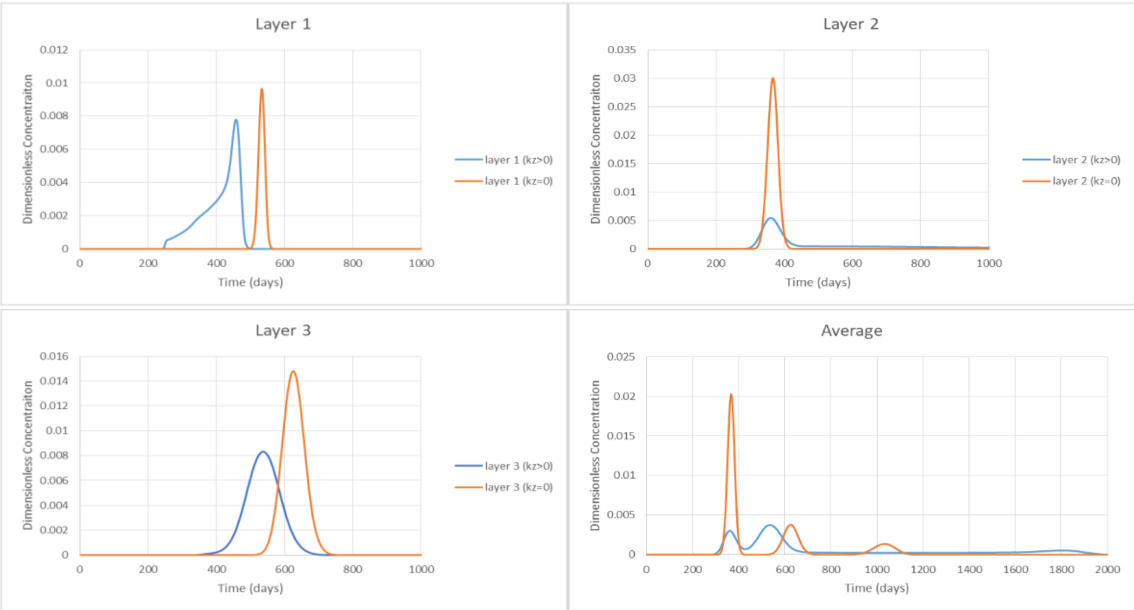

Figure 5.23: Comparison of conservative tracer responses for k_z=0 and $k_z > 0$.

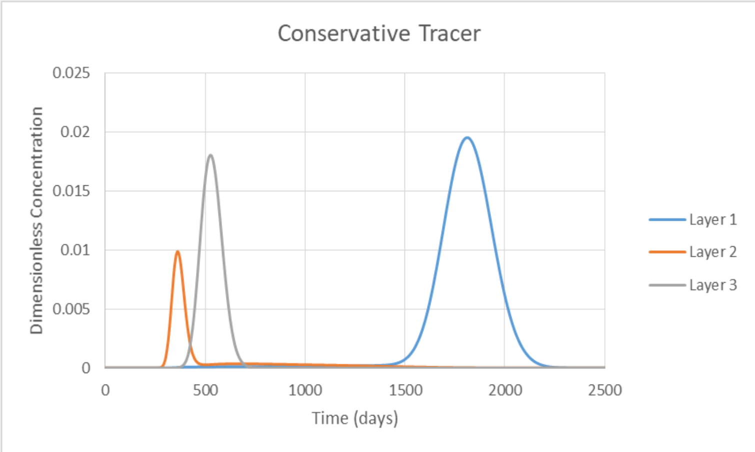

Figure 5.24: Conservative tracer response per layer.

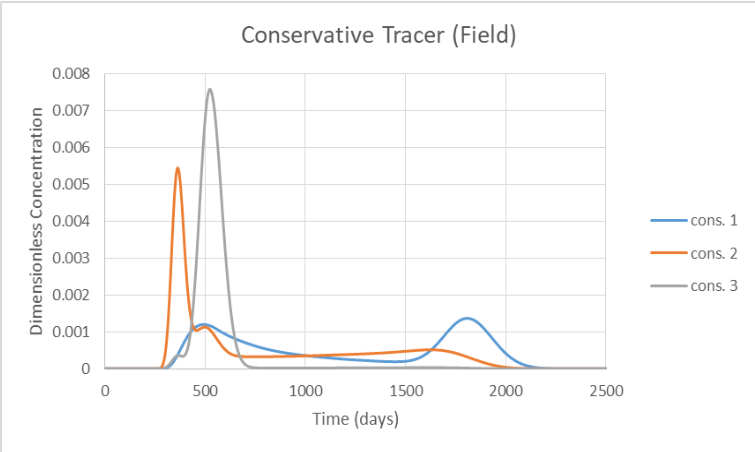

Figure 5.25: Conservative tracer average (field) response per layer.

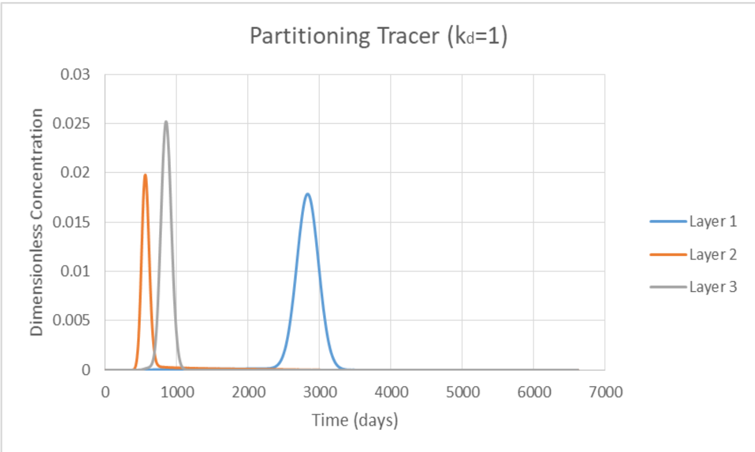

Figure 5.26: Partitioning tracer (k_d= 1) per layer response.

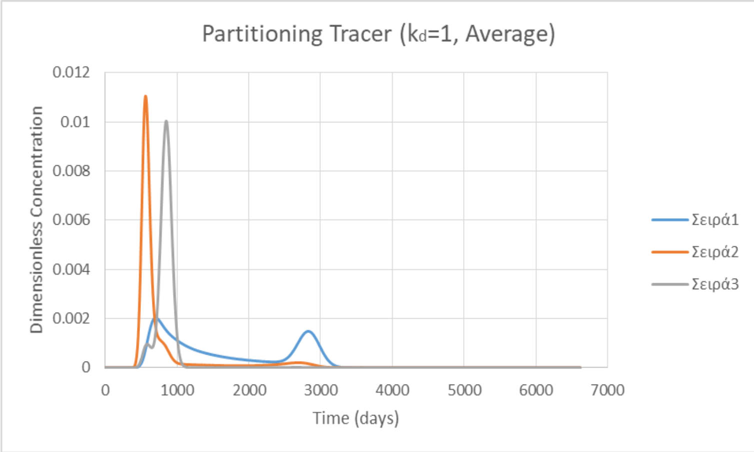

Figure 5.27: Partitioning tracer (k_d= 1) average (field) response per layer.

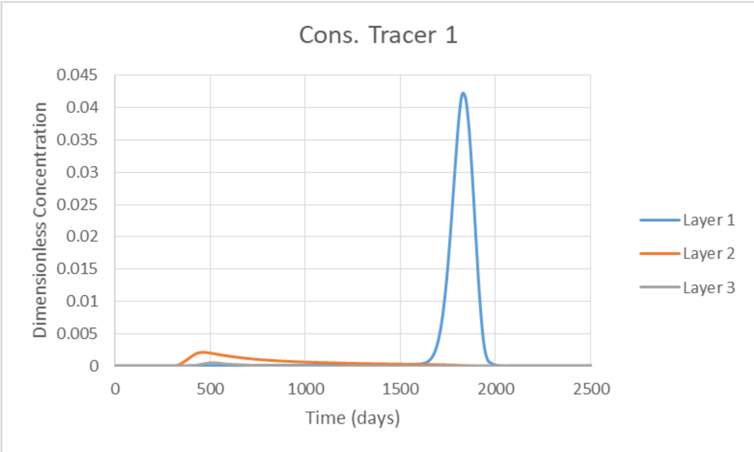

Figure 5.28: Conservative tracer (injected at layer 1) response for all three connections.

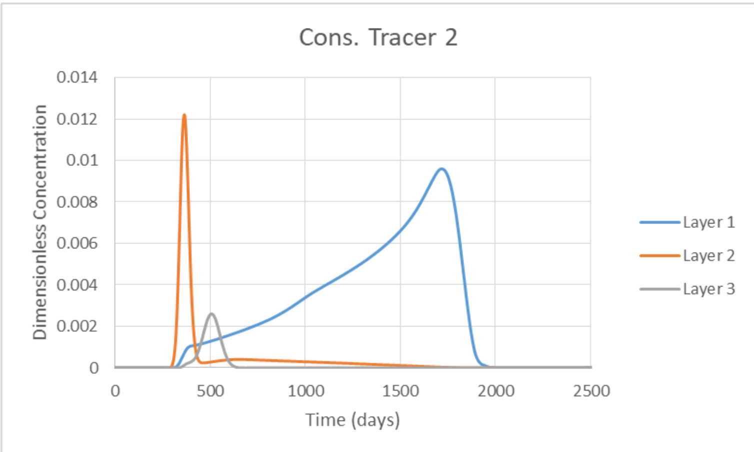

Figure 5.29: Conservative tracer (injected at layer 2) response for all three connections.

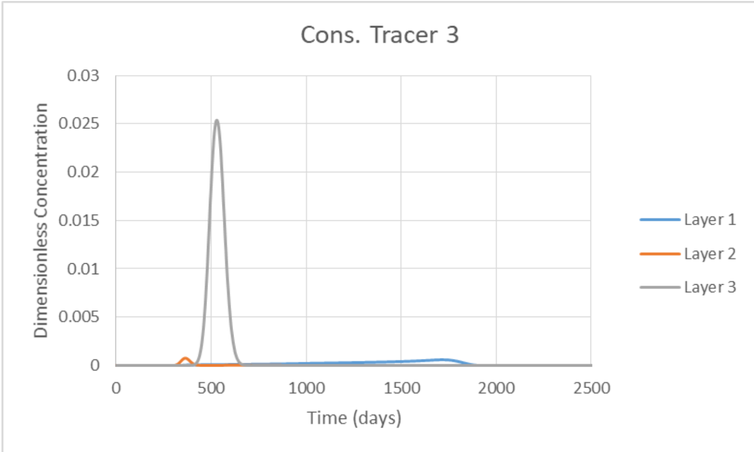

Figure 5.30: Conservative tracer (injected at layer 2) response for all three connections.

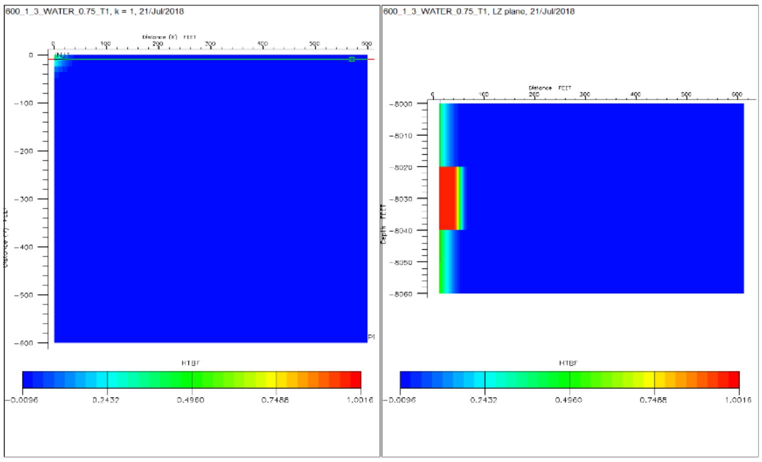

Figure 5.31: Cross section of conservative tracer (originally injected at layer 2) response in all layers after 3 days of injection.

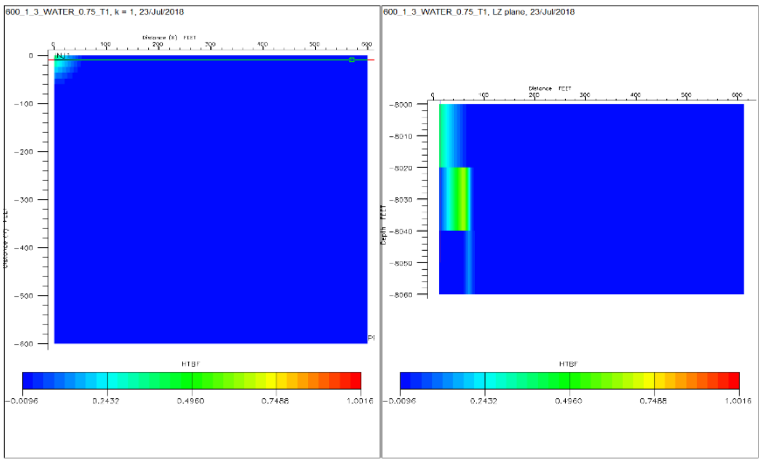

Figure 5.32: Cross section of conservative tracer (originally injected at layer 2) response in all layers after 5 days of injection.

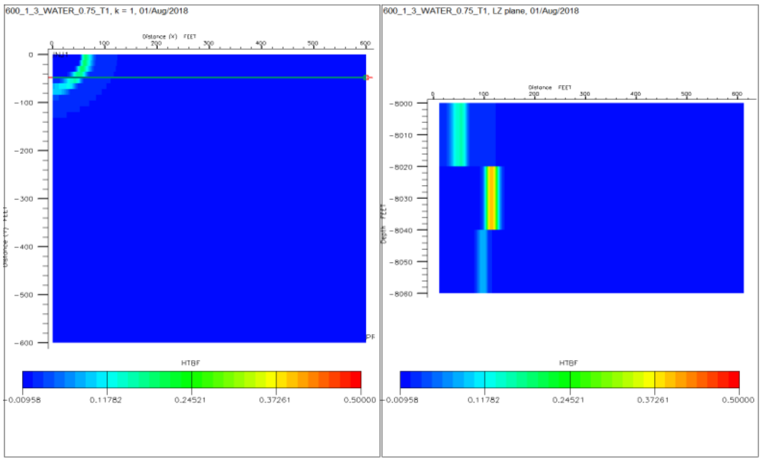

Figure 5.33: Cross section of conservative tracer (originally injected at layer 2) response in all layers after 13 days of injection.

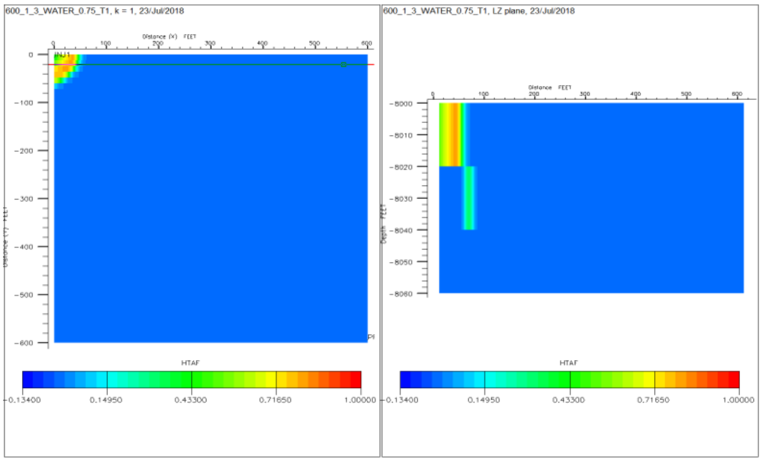

Figure 5.34: Cross section of conservative tracer (originally injected at layer 1) response in all layers after 2 days of injection.

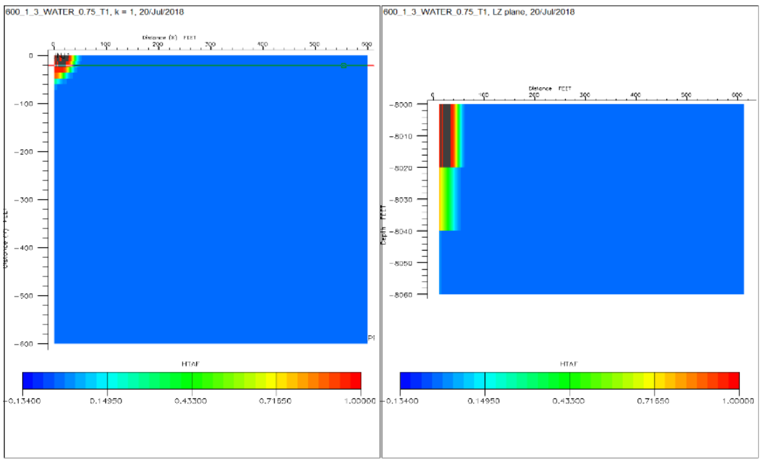

Figure 5.35: Cross section of conservative tracer (originally injected at layer 1) response in all layers after 5 days of injection.

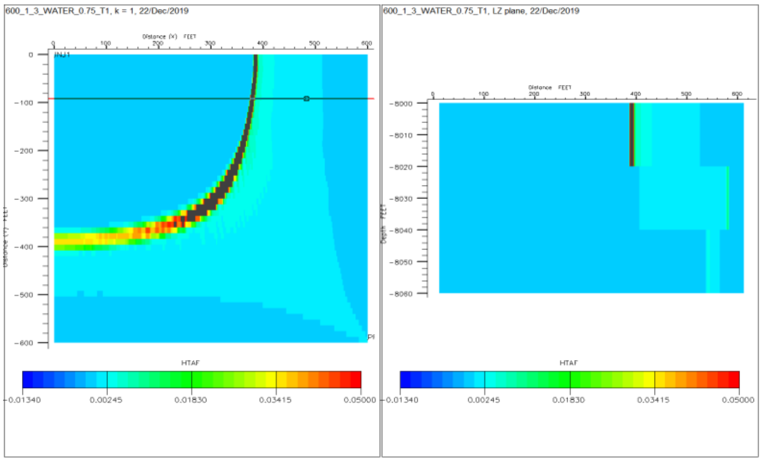

Figure 5.36: Cross section of conservative tracer (originally injected at layer 1) response in all layers after 5 months of injection.

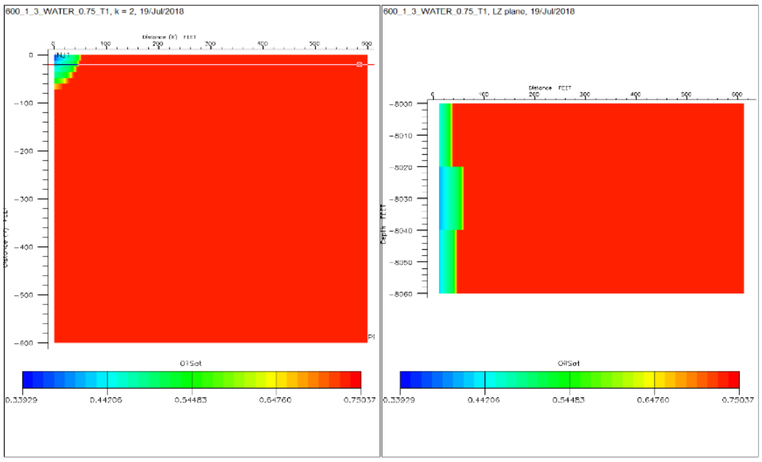

Figure 5.37: Cross section of oil saturation after 1 day of production.

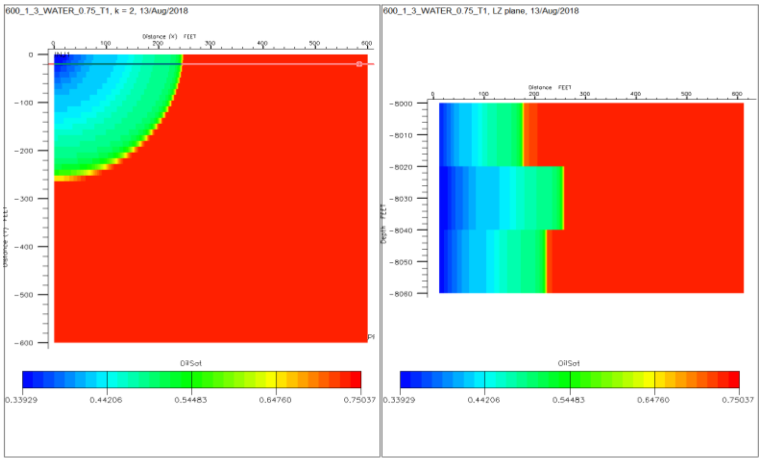

Figure 5.38: Cross section of oil saturation after (nearly) a month of production.

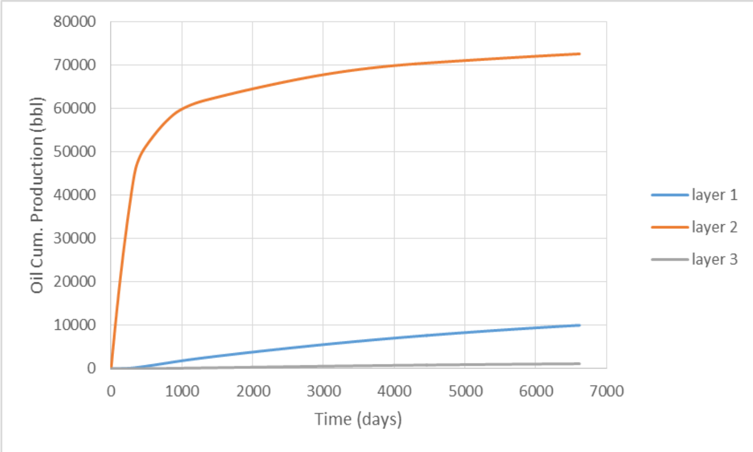

Figure 5.39: Cumulative oil production per layer over time.

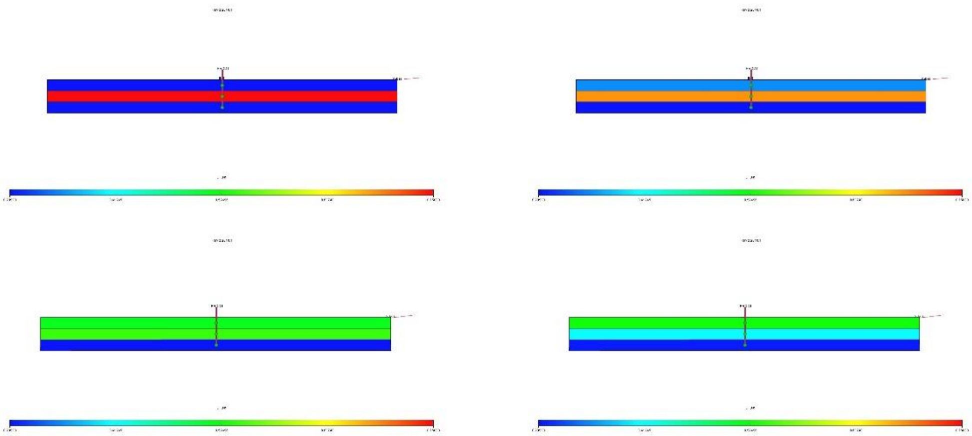

Figure 5.40: Oil saturation over time for each layer.

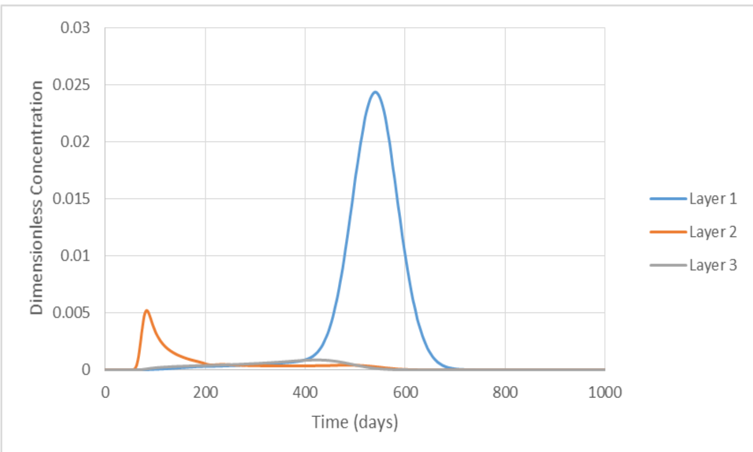

Figure 5.41: Conservative tracer (originally injected at layer 1) response in all three connections in the water-wet system (S_{oi}= 0.75).

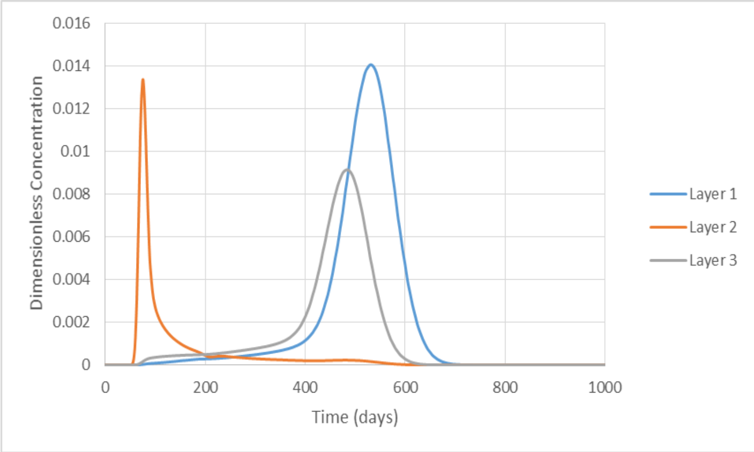

Figure 5.42: Conservative tracer (originally injected at layer 2) response in all three connections in the water-wet system (S_{oi}= 0.75).

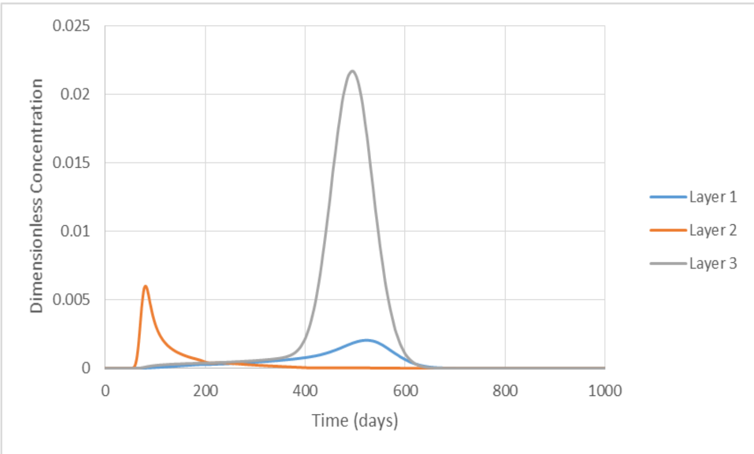

Figure 5.43: Conservative tracer (originally injected at layer 3) response in all three connections in the water-wet system (S_{oi}= 0.75).

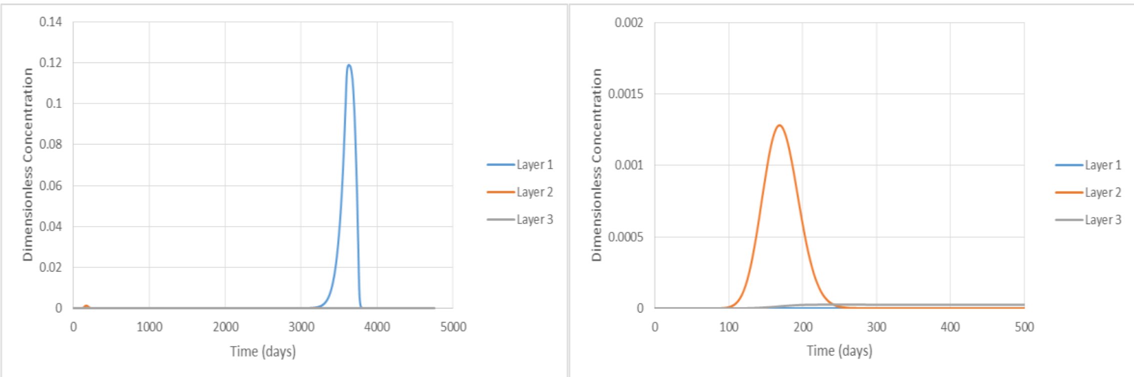

Figure 5.44: Conservative tracer (originally injected at layer 1) response in all three connections in the oil-wet system (S_{oi}= 0.65).

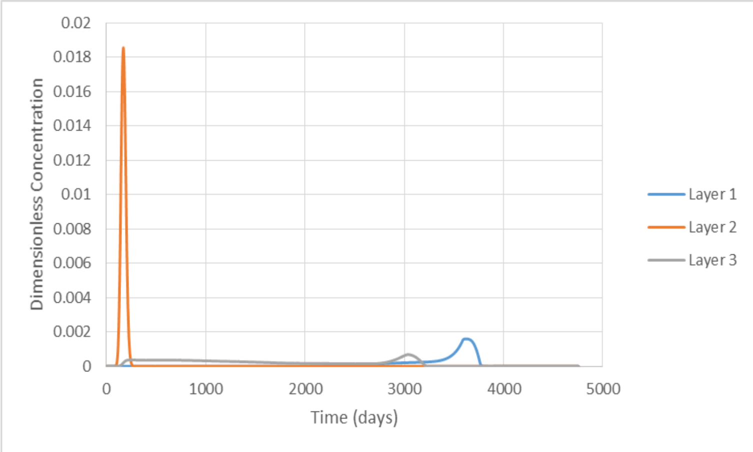

Figure 5.45: Conservative tracer (originally injected at layer 2) response in all three connections in the oil-wet system (S_{oi}= 0.65).

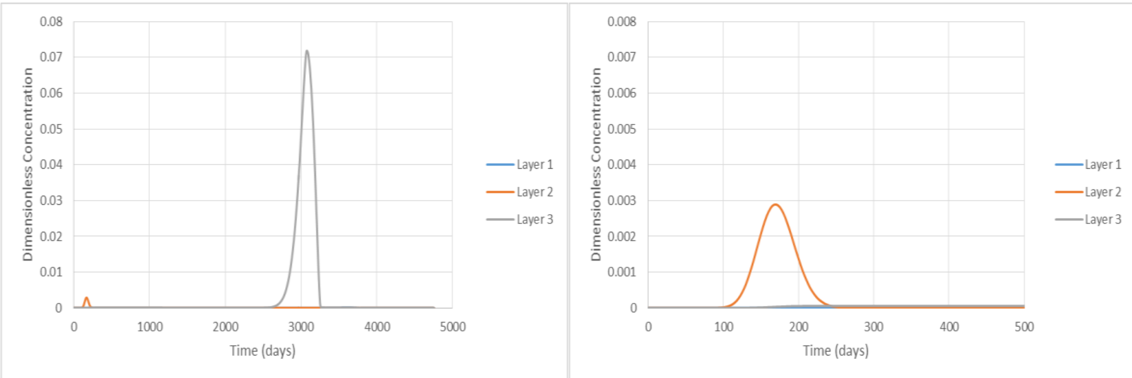

Figure 5.46: Conservative tracer (originally injected at layer 3) response in all three connections in the water-wet system (S_{oi}= 0.75).

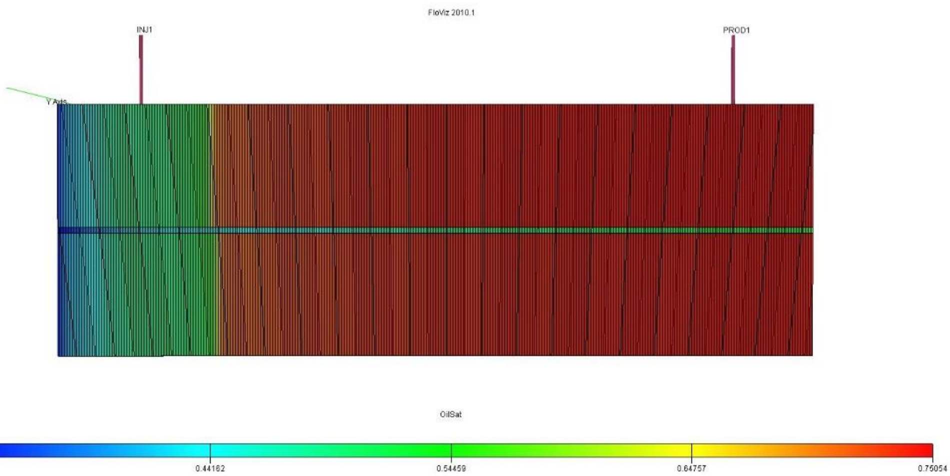

Figure 5.47: Oil saturation during production.

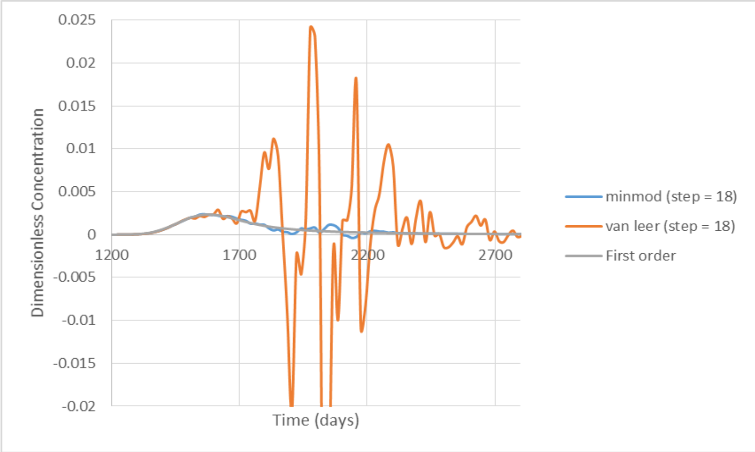

Figure 5.48: Conservative tracer response for various implemented schemes.

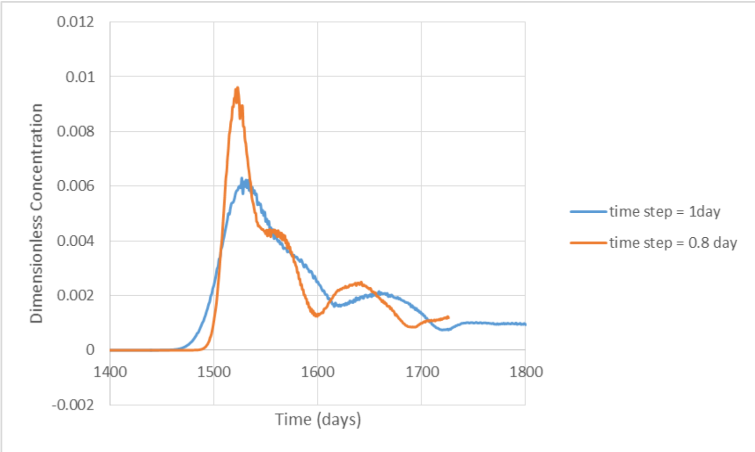

Figure 5.49: Conservative tracer response for 1 and 0.8 day time step in the 2nd order Minmod flux limiting scheme.

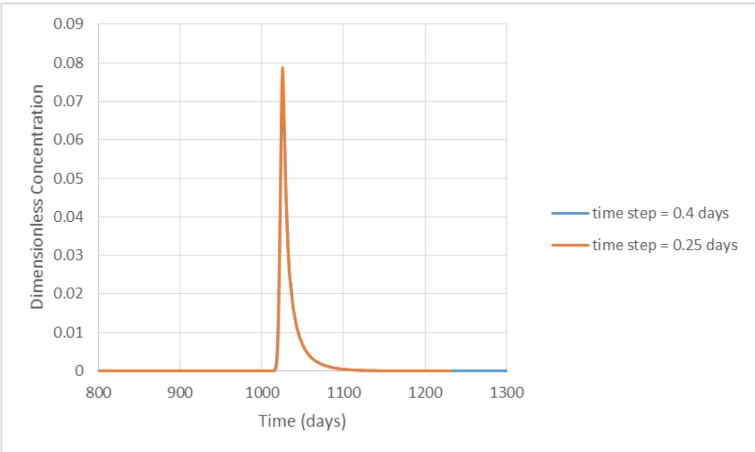

Figure 5.50: Conservative tracer response for a smaller distance between the injector and the producer.

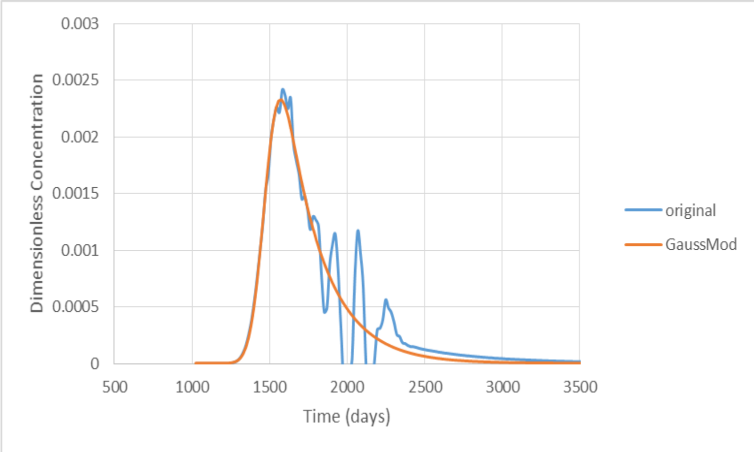

Figure 5.51: Example of Gauss Mod curve fitting in tracer concentration data.

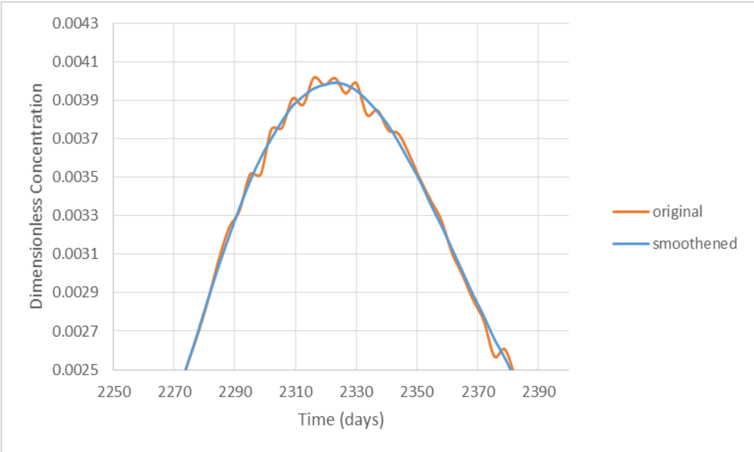

Figure 5.52: Example of smoothening filter (of 32 points) in tracer concentration data.

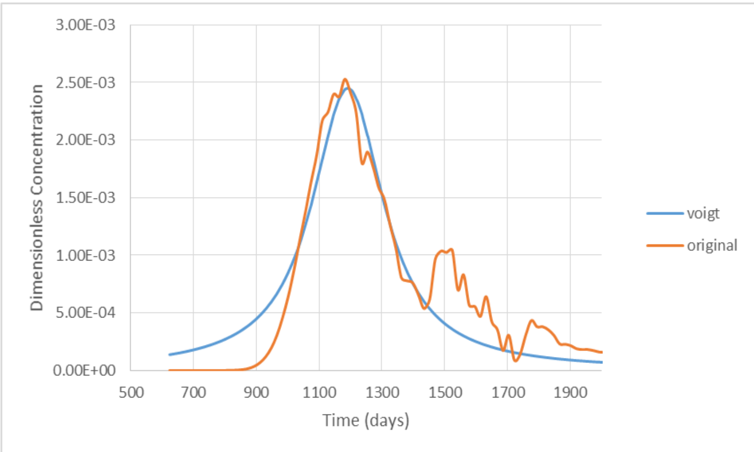

Figure 5.53: Example of Voigt- type curve fitting in tracer concentration data.

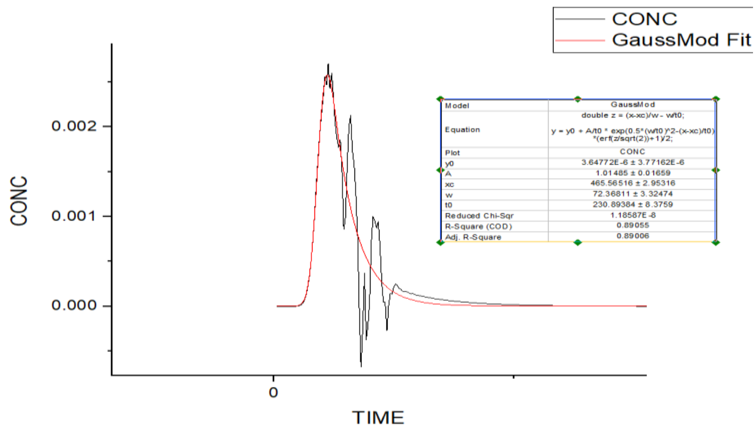

Figure 5.54: Example of Gauss Mod curve fitting in tracer concentration data, as generated from ORIGIN PRO.

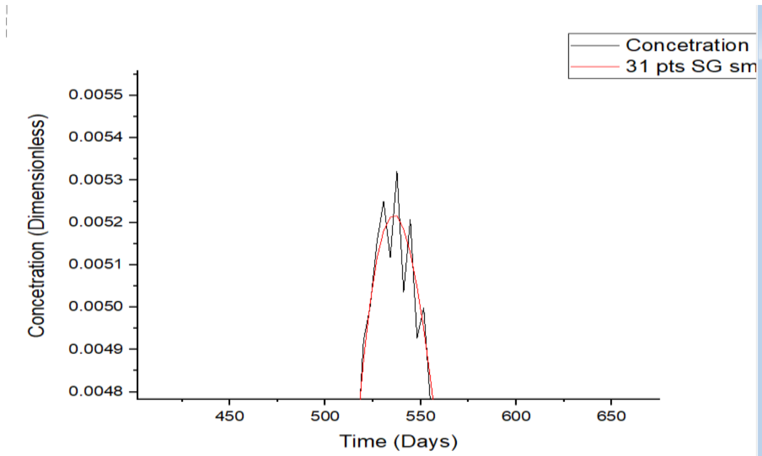

Figure 5.55: Example of smoothening filters in tracer concentration data, as generated from ORIGIN PRO.

Tables of chapter 5

Homogeneous Reservoir	
No. of blocks in x direction	200
No. of blocks in y direction	200
No. of blocks in z direction	1
D_x (per block)	5 ft.
D_y (per block)	5 ft.
D_z (per block)	90 ft.
Reservoir depth	8000 ft.
porosity (constant)	0.25
X permeability	1000 mD
Y permeability	1000 mD
Z permeability	100 mD
water saturation (average)	0.75 / 0.5
Residual Oil Sturation (S_{or})	0.385/ 0.338
oil density	49 ppg
water density	63 ppg
Oil viscosity	1.74 cP (@Pres)
Water viscosity	0.8 cP
water compressiblity	3E-06 1/psi
rock compressibility	4E-06 1/psi
B_w	1.02
B_o @ Pres	1.17
reservoir pressure	4500 psi
Production rate	3000 stb/day
Injection rate	3000 stb/day
wellbore radius	4 inches

Table 5.1: Reservoir and grid properties for the homogenous case of the mobile oil study.

Water-Wet (S_{oi}= 0.75) 1st Peak						Water-Wet (Soi= 0.75) 2nd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %	cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
537.00	702.00	0.5	**0.3806**	0.51	24.65	1414.51	1586.01	0.5	**0.3900**	0.41	5.67
537.00	863.00	1	**0.3777**	0.50	24.61	1414.51	1743.51	1	**0.3801**	0.41	7.70
537.00	1017.26	1.5	**0.3735**	0.50	25.00	1414.51	1899.51	1.5	**0.3760**	0.41	8.39
537.00	1167.76	2	**0.3700**	0.50	25.33	1414.51	2055.26	2	**0.3739**	0.41	8.91

Water-Wet (Soi= 0.75) 3rd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
2303.76	2477.01	0.5	**0.3870**	0.40	3.34
2303.76	2627.51	1	**0.3711**	0.40	7.11
2303.76	2776.26	1.5	**0.3647**	0.40	8.51
2303.76	2921.51	2	**0.3601**	0.40	9.46

Table 5.2: Results from mode time for all slugs in the water-wet case (S_{oi}= 0.75).

Water-Wet (S_{oi}= 0.5) 1st Peak						Water-Wet (Soi= 0.5) 2nd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %	cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
528.75	705.50	0.5	**0.4011**	0.44	9.74	1421.51	1589.51	0.5	**0.3820**	0.41	7.47
528.75	873.50	1	**0.3951**	0.44	10.32	1421.51	1747.01	1	**0.3746**	0.41	8.95
528.75	1029.51	1.5	**0.3875**	0.44	11.48	1421.51	1903.01	1.5	**0.3713**	0.41	9.44
528.75	1180.01	2	**0.3816**	0.44	12.34	1421.51	2060.51	2	**0.3702**	0.41	9.43

Water-Wet (Soi= 0.5) 3rd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
2323.01	2480.51	0.5	**0.3567**	0.40	10.37
2323.01	2631.01	1	**0.3516**	0.40	11.45
2323.01	2778.01	1.5	**0.3481**	0.40	12.14
2323.01	2925.01	2	**0.3464**	0.40	12.40

Table 5.3: Results from mode time for all slugs in the water-wet case (S_{oi}= 0.5).

Oil-Wet (S_{oi}= 0.75) 1st Peak						Oil-Wet (Soi= 0.75) 2nd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %	cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
464.00	649.50	0.5	**0.4448**	0.51	12.85	1369.005	1547.505	0.5	**0.4210**	0.47	10.86
464.00	831.50	1	**0.4425**	0.51	12.45	1369.005	1720.755	1	**0.4174**	0.47	11.28
464.00	1008.51	1.5	**0.4395**	0.50	12.42	1369.005	1892.505	1.5	**0.4155**	0.47	11.39
464.00	1190.51	2	**0.4396**	0.50	11.86	1369.005	2062.255	2	**0.4138**	0.47	11.47

Oil-Wet (Soi= 0.75) 3rd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
2263.505	2435.005	0.5	**0.4028**	0.46	11.74
2263.505	2610.005	1	**0.4053**	0.46	11.00
2263.505	2781.505	1.5	**0.4044**	0.45	10.99
2263.505	2951.255	2	**0.4034**	0.45	11.04

Table 5.4: Results from mode time for all slugs in the oil-wet case (S_{oi}= 0.75).

Oil-Wet (S_{oi}= 0.5) 1st Peak						Oil-Wet (Soi= 0.5) 2nd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %	cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
516.5048	726.5048	0.5	**0.4490**	0.49	7.64	1390.005	1586.005	0.5	**0.4336**	0.47	7.33
516.5048	922.7548	1	**0.4407**	0.48	8.92	1390.005	1750.505	1	**0.4132**	0.47	11.45
516.5048	1106.505	1.5	**0.4328**	0.48	10.39	1390.005	1924.005	1.5	**0.4101**	0.47	11.85
516.5048	1288.505	2	**0.4282**	0.48	10.80	1390.005	2092.005	2	**0.4067**	0.46	12.37

Oil-Wet (Soi= 0.5) 3rd Peak					
cons. t_{mode}	part. t_{mode}	k_d	Predicted S_o	Average S_o	Deviation %
2270.51	2445.51	0.5	**0.4044**	0.46	11.17
2270.51	2620.51	1	**0.4044**	0.45	10.97
2270.51	2792.01	1.5	**0.4028**	0.45	11.15
2270.51	2963.51	2	**0.4020**	0.45	11.16

Table 5.5: Results from mode time for all slugs in the oil-wet case (S_{oi}= 0.5).

Water-Wet (Soi= 0.75) @ day 1								Water-Wet (Soi= 0.75) @ day 600							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R	k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	769.87	1032.15	**0.4052**	16.13	21804575	0.969	1.34	0.5	786.71	1000.78	**0.3524**	1.19	20464021	0.910	1.27
1	769.87	1274.71	**0.3960**	13.50	21472406	0.954	1.66	1	786.71	1225.65	**0.3581**	2.83	20646140	0.918	1.56
1.5	769.87	1499.38	**0.3871**	10.95	21160916	0.940	1.95	1.5	786.71	1448.65	**0.3594**	3.18	20685752	0.919	1.84
1.8	769.87	1713.24	**0.3799**	8.88	20914030	0.930	2.23	1.8	786.71	1672.78	**0.3603**	3.44	20715073	0.921	2.13
Water-Wet (Soi= 0.75) @ day 1000								Water-Wet (Soi= 0.75) @ day 3000							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R	k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	794.00	1010.64	**0.3530**	1.48	20673651	0.919	1.27	0.5	836.02	1036.22	**0.3238**	6.47	20827551	0.926	1.24
1	794.00	1236.87	**0.3581**	2.92	20835148	0.926	1.56	1	836.02	1251.68	**0.3321**	4.09	21084487	0.937	1.50
1.5	794.00	1462.77	**0.3596**	3.36	20885175	0.928	1.84	1.5	836.02	1464.62	**0.3339**	3.56	21141900	0.940	1.75
1.8	794.00	1688.57	**0.3603**	3.58	20909422	0.929	2.13	1.8	836.02	1675.04	**0.3341**	3.49	21149401	0.940	2.00

Table 5.6: Results from mean residence time for all slugs in the water-wet case (S_{oi}= 0.75).

Water-Wet (Soi= 0.5) @ day 1								Water-Wet (Soi= 0.5) @ day 600							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R	k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	767.07	1029.46	**0.4062**	16.40	21761385	0.967	1.34	0.5	799.75	1014.25	**0.3491**	1.19	20698386	0.920	1.27
1	767.07	1276.01	**0.3989**	14.29	21494306	0.955	1.66	1	799.75	1240.26	**0.3552**	2.83	20892129	0.929	1.55
1.5	767.07	1504.90	**0.3907**	11.96	21207127	0.943	1.96	1.5	799.75	1462.74	**0.3559**	3.18	20917165	0.930	1.83
1.8	767.07	1721.69	**0.3836**	9.91	20961534	0.932	2.24	1.8	799.75	1685.48	**0.3564**	3.44	20931828	0.930	2.11
Water-Wet (Soi= 0.5) @ day 1000								Water-Wet (Soi= 0.5) @ day 3000							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R	k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	800.91	1015.91	**0.3493**	1.48	20734718	0.922	1.27	0.5	827.63	1036.97	**0.3359**	3.02	20994104	0.933	1.25
1	800.91	1242.78	**0.3555**	2.92	20934704	0.930	1.55	1	827.63	1253.69	**0.3398**	1.89	21118459	0.939	1.51
1.5	800.91	1468.82	**0.3573**	3.36	20991977	0.933	1.83	1.5	827.63	1467.76	**0.3402**	1.78	21130066	0.939	1.77
1.8	800.91	1695.23	**0.3583**	3.58	21023802	0.934	2.12	1.8	827.63	1679.25	**0.3397**	1.92	21114248	0.938	2.03

Table 5.7: Results from mean residence time for all slugs in the water-wet case (S_{oi}= 0.5).

Oil-Wet (Soi= 0.75) @ day 1								Oil-Wet (Soi= 0.75) @ day 1000							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R	k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	687.70	969.55	**0.4505**	10.93	21079840	0.937	1.41	0.5	706.77	972.52	**0.4292**	6.02	20858639	0.927	1.38
1	687.70	1232.35	**0.4420**	8.83	20758893	0.923	1.79	1	706.77	1231.63	**0.4261**	5.26	20746777	0.922	1.74
1.5	687.70	1493.90	**0.4387**	8.03	20637973	0.917	2.17	1.5	706.77	1483.70	**0.4229**	4.46	20630429	0.917	2.10
1.8	687.70	1760.72	**0.4382**	7.92	20621837	0.917	2.56	1.8	706.77	1729.46	**0.4198**	3.69	20519153	0.912	2.45
Oil-Wet (Soi= 0.75) @ day 3000								Oil-Wet (Soi= 0.75) @ day 600							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R	k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	740.32	991.48	**0.4042**	0.39	20932308	0.930	1.34	0.5	689.64	961.27	**0.4406**	8.71	20768266	0.923	1.39
1	740.32	1240.12	**0.4030**	0.08	20889771	0.928	1.68	1	689.64	1228.40	**0.4386**	8.21	20692477	0.920	1.78
1.5	740.32	1487.36	**0.4022**	0.13	20859969	0.927	2.01	1.5	689.64	1488.31	**0.4357**	7.49	20586025	0.915	2.16
1.8	740.32	1733.86	**0.4016**	0.28	20838819	0.926	2.34	1.8	689.64	1739.22	**0.4321**	6.61	20457128	0.909	2.52

Table 5.8: Results from mean residence time for all slugs in the oil-wet case (S_{oi}= 0.75).

Oil-Wet (Soi= 0.5) @ day 1							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	699.60	981.74	**0.4465**	10.93	21289915	0.946	1.40
1	699.60	1275.30	**0.4514**	8.83	21482435	0.955	1.82
1.5	699.60	1560.12	**0.4506**	8.03	21448407	0.953	2.23
1.8	699.60	1839.63	**0.4490**	7.92	21386720	0.951	2.63

Oil-Wet (Soi= 0.5) @ day 600							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	721.48	1005.55	**0.4405**	8.71	21723584	0.965	1.39
1	721.48	1283.10	**0.4377**	8.21	21613814	0.961	1.78
1.5	721.48	1550.62	**0.4338**	7.49	21464602	0.954	2.15
1.8	721.48	1806.88	**0.4293**	6.61	21295139	0.946	2.50

Oil-Wet (Soi= 0.5) @ day 1000							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	726.30	1000.98	**0.4306**	6.02	21488422	0.955	1.38
1	726.30	1267.71	**0.4271**	5.26	21354613	0.949	1.75
1.5	726.30	1525.45	**0.4231**	4.46	21208930	0.943	2.10
1.8	726.30	1775.84	**0.4195**	3.69	21074259	0.937	2.45

Oil-Wet (Soi= 0.5) @ day 3000							
k_d	mrt_{cons}	mrt_{part}	S_{OR}	Variation (%)	V_p (cft)	Swept Vol %	R
0.5	741.85	995.20	**0.4058**	0.39	21031864	0.935	1.34
1	741.85	1246.24	**0.4047**	0.08	20992853	0.933	1.68
1.5	741.85	1495.84	**0.4039**	0.13	20963792	0.932	2.02
1.8	741.85	1744.62	**0.4033**	0.28	20942321	0.931	2.35

Table 5.9: Results from mean residence time for all slugs in the oil-wet case (S_{oi}= 0.5).

Water-Wet (Soi= 0.75) @ day 1									
k_d	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	1453.97	2080.01	610.36	681.23	535.56	690.09	**0.4627**	**0.1884**	**0.3659**
1	1453.97	2569.67	610.36	770.71	535.56	828.22	**0.4342**	**0.2081**	**0.3534**
1.5	1453.97	2896.40	610.36	857.46	535.56	971.70	**0.3981**	**0.2125**	**0.3519**
2	1453.97	3201.28	610.36	948.27	535.56	1114.88	**0.3753**	**0.2168**	**0.3510**

Water-Wet (Soi= 0.75) @ day 100									
k_d	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	1617.64	2145.06	394.86	529.75	507.45	659.29	**0.3947**	**0.4059**	**0.3744**
1	1617.64	2483.98	394.86	661.44	507.45	811.25	**0.3488**	**0.4030**	**0.3745**
1.5	1617.64	2813.68	394.86	782.99	507.45	958.37	**0.3302**	**0.3959**	**0.3720**
2	1617.64	3145.76	394.86	899.85	507.45	1101.66	**0.3208**	**0.3900**	**0.3693**

Water-Wet (Soi= 0.75) @ day 300									
k_d	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	1747.25	2184.29	422.21	562.61	512.94	664.87	**0.3334**	**0.3994**	**0.3720**
1	1747.25	2559.24	422.21	696.97	512.94	812.01	**0.3173**	**0.3942**	**0.3683**
1.5	1747.25	2907.20	422.21	822.28	512.94	953.52	**0.3068**	**0.3871**	**0.3641**
2	1747.25	3250.25	422.21	943.40	512.94	1091.02	**0.3007**	**0.3817**	**0.3604**

Water-Wet (Soi= 0.75) @ day 600									
k_d	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	1702.65	2146.79	441.85	582.08	520.90	665.82	**0.3428**	**0.3883**	**0.3575**
1	1702.65	2532.19	441.85	711.95	520.90	806.61	**0.3276**	**0.3794**	**0.3542**
1.5	1702.65	2892.06	441.85	834.57	520.90	944.92	**0.3177**	**0.3721**	**0.3518**
2	1702.65	3243.64	441.85	954.12	520.90	1081.04	**0.3115**	**0.3670**	**0.3497**

Water-Wet (Soi= 0.75) @ day 1000									
k_d	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	1661.81	2091.85	460.72	591.84	527.64	668.14	**0.3410**	**0.3627**	**0.3475**
1	1661.81	2479.74	460.72	714.36	527.64	806.16	**0.3298**	**0.3551**	**0.3455**
1.5	1661.81	2852.33	460.72	831.12	527.64	942.67	**0.3232**	**0.3489**	**0.3440**
2	1661.81	3219.84	460.72	946.33	527.64	1078.33	**0.3192**	**0.3451**	**0.3429**

Table 5.10: S_o predictions per layer, obtained from mean residence time in the case where the same tracers are being injected at all connections, over time, in the water-wet reservoir (S_{oi}= 0.75).

Water-Wet (Soi= 0.5) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1792.22	2205.43	454.46	600.50	495.87	658.74	**0.3156**	**0.3912**	**0.3965**
1	1792.22	2552.08	454.46	742.43	495.87	809.24	**0.2977**	**0.3879**	**0.3872**
1.5	1792.22	2875.46	454.46	860.30	495.87	957.44	**0.2872**	**0.3732**	**0.3829**
2	1792.22	3196.99	454.46	966.30	495.87	1104.56	**0.2816**	**0.3603**	**0.3803**

Water-Wet (Soi= 0.5) @ day 100									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1787.44	2153.62	409.36	547.81	492.24	646.35	**0.2906**	**0.4035**	**0.3850**
1	1787.44	2496.01	409.36	680.95	492.24	799.70	**0.2839**	**0.3988**	**0.3845**
1.5	1787.44	2823.74	409.36	801.63	492.24	950.61	**0.2788**	**0.3898**	**0.3830**
2	1787.44	3153.21	409.36	917.41	492.24	1095.91	**0.2764**	**0.3829**	**0.3801**

Water-Wet (Soi= 0.5) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1751.02	2182.22	424.79	564.45	501.72	656.04	**0.3300**	**0.3967**	**0.3809**
1	1751.02	2555.65	424.79	699.93	501.72	805.58	**0.3148**	**0.3931**	**0.3772**
1.5	1751.02	2900.57	424.79	824.80	501.72	950.23	**0.3044**	**0.3857**	**0.3734**
2	1751.02	3240.11	424.79	944.88	501.72	1090.39	**0.2983**	**0.3797**	**0.3697**

Water-Wet (Soi= 0.5) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1705.74	2154.26	437.04	578.81	514.82	662.35	**0.3447**	**0.3935**	**0.3643**
1	1705.74	2539.77	437.04	711.17	514.82	805.35	**0.3284**	**0.3855**	**0.3607**
1.5	1705.74	2897.74	437.04	834.93	514.82	945.24	**0.3178**	**0.3777**	**0.3579**
2	1705.74	3253.97	437.04	961.83	514.82	1089.94	**0.3122**	**0.3752**	**0.3584**

Water-Wet (Soi= 0.5) @ day 1000									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1662.78	2100.25	457.77	592.22	523.53	665.16	**0.3448**	**0.3700**	**0.3511**
1	1662.78	2489.47	457.77	717.51	523.53	803.66	**0.3321**	**0.3620**	**0.3486**
1.5	1662.78	2859.04	457.77	836.83	523.53	940.55	**0.3242**	**0.3557**	**0.3468**
2	1662.78	3222.18	457.77	953.81	523.53	1076.36	**0.3192**	**0.3514**	**0.3455**

Table 5.11: S_o predictions per layer, obtained from mean residence time in the case where the same tracers are being injected at all connections, over time, in the water-wet reservoir (S_{oi}= 0.5).

Oil-Wet (Soi= 0.75) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	703.43	1202.14	283.77	446.03	458.68	683.42	**0.5864**	**0.5335**	**0.4949**
1	703.43	1766.37	283.77	601.62	458.68	897.51	**0.6018**	**0.5283**	**0.4889**
1.5	703.43	2442.57	283.77	756.67	458.68	1110.54	**0.6224**	**0.5263**	**0.4865**
2	703.43	3262.49	283.77	908.69	458.68	1326.87	**0.6453**	**0.5241**	**0.4862**

Oil-Wet (Soi= 0.75) @ day 100									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	775.39	1856.16	292.35	599.67	454.68	891.25	**0.7360**	**0.6777**	**0.6576**
1	775.39	1856.16	292.35	599.67	454.68	891.25	**0.5823**	**0.5125**	**0.4898**
1.5	775.39	2556.19	292.35	750.80	454.68	1105.97	**0.6049**	**0.5111**	**0.4885**
2	775.39	3349.80	292.35	897.69	454.68	1318.21	**0.6241**	**0.5087**	**0.4871**

Oil-Wet (Soi= 0.75) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	826.53	1359.96	293.28	444.24	448.56	666.32	**0.5635**	**0.5073**	**0.4926**
1	826.53	1970.00	293.28	592.69	448.56	880.57	**0.5804**	**0.5052**	**0.4906**
1.5	826.53	2670.46	293.28	737.16	448.56	1090.54	**0.5980**	**0.5022**	**0.4883**
2	826.53	3399.79	293.28	877.53	448.56	1296.17	**0.6089**	**0.4990**	**0.4858**

Oil-Wet (Soi= 0.75) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	886.56	1438.74	294.36	438.75	446.13	658.45	**0.5547**	**0.4952**	**0.4877**
1	886.56	2082.10	294.36	579.60	446.13	868.22	**0.5742**	**0.4921**	**0.4862**
1.5	886.56	2785.05	294.36	717.46	446.13	1076.31	**0.5881**	**0.4893**	**0.4850**
2	886.56	3506.09	294.36	853.99	446.13	1282.92	**0.5963**	**0.4873**	**0.4840**

Oil-Wet (Soi= 0.75) @ day 1000									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	953.61	1559.25	294.63	432.92	450.22	659.05	**0.5595**	**0.4842**	**0.4812**
1	953.61	2239.81	294.63	569.81	450.22	865.72	**0.5742**	**0.4829**	**0.4800**
1.5	953.61	2939.03	294.63	706.40	450.22	1069.45	**0.5812**	**0.4823**	**0.4783**
2	953.61	3632.41	294.63	844.04	450.22	1267.60	**0.5841**	**0.4825**	**0.4758**

Table 5.12: S_o predictions per layer, obtained from mean residence time in the case where the same tracers are being injected at all connections, over time, in the oil-wet reservoir (S_{oi}= 0.75).

Oil-Wet (Soi= 0.65) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	761.47	1213.62	281.07	441.97	452.32	683.32	**0.5429**	**0.5338**	**0.5053**
1	761.47	1769.51	281.07	598.26	452.32	899.62	**0.5697**	**0.5302**	**0.4972**
1.5	761.47	2438.58	281.07	753.01	452.32	1113.71	**0.5949**	**0.5282**	**0.4936**
2	761.47	3255.32	281.07	904.94	452.32	1331.61	**0.6209**	**0.5260**	**0.4929**

Oil-Wet (Soi= 0.65) @ day 100									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	772.32	1260.85	291.42	444.58	455.38	678.33	**0.5585**	**0.5125**	**0.4947**
1	772.32	1846.38	291.42	598.21	455.38	894.72	**0.5817**	**0.5128**	**0.4910**
1.5	772.32	2543.83	291.42	749.17	455.38	1110.87	**0.6046**	**0.5115**	**0.4897**
2	772.32	3339.70	291.42	896.07	455.38	1325.25	**0.6244**	**0.5092**	**0.4885**

Oil-Wet (Soi= 0.65) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	822.48	1354.01	292.38	443.20	449.55	668.33	**0.5638**	**0.5078**	**0.4932**
1	822.48	1962.59	292.38	591.48	449.55	883.61	**0.5809**	**0.5057**	**0.4912**
1.5	822.48	2663.45	292.38	735.85	449.55	1095.03	**0.5988**	**0.5028**	**0.4891**
2	822.48	3393.16	292.38	876.07	449.55	1301.30	**0.6098**	**0.4995**	**0.4865**

Oil-Wet (Soi= 0.65) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	883.84	1434.30	293.70	437.86	446.78	660.13	**0.5547**	**0.4954**	**0.4885**
1	883.84	2074.91	293.70	578.58	446.78	870.79	**0.5740**	**0.4924**	**0.4869**
1.5	883.84	2778.49	293.70	716.32	446.78	1079.63	**0.5883**	**0.4896**	**0.4857**
2	883.84	3500.69	293.70	852.70	446.78	1286.85	**0.5968**	**0.4876**	**0.4846**

Oil-Wet (Soi= 0.65) @ day 1000									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	950.67	1553.43	294.08	432.26	450.78	660.39	**0.5591**	**0.4845**	**0.4819**
1	950.67	2233.81	294.08	569.03	450.78	867.74	**0.5744**	**0.4832**	**0.4805**
1.5	950.67	2933.70	294.08	705.50	450.78	1072.22	**0.5817**	**0.4826**	**0.4789**
2	950.67	3628.05	294.08	843.05	450.78	1271.48	**0.5847**	**0.4828**	**0.4765**

Table 5.13: S_o predictions per layer, obtained from mean residence time in the case where the same tracers are being injected at all connections, over time, in the oil-wet reservoir (S_{oi}= 0.65).

Water-Wet (Soi= 0.75) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1792.72	2346.03	523.65	564.31	528.02	693.62	**0.3817**	**0.1344**	**0.3855**
1	1792.72	2799.40	523.65	635.63	528.02	845.39	**0.3596**	**0.1762**	**0.3754**
1.5	1792.72	3196.14	523.65	715.91	528.02	989.15	**0.3429**	**0.1966**	**0.3680**
2	1793.34	3575.84	522.50	805.37	530.13	1129.58	**0.3320**	**0.2130**	**0.3612**

Water-Wet (Soi= 0.75) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1745.01	2248.56	356.88	466.91	525.20	673.74	**0.3659**	**0.3814**	**0.3613**
1	1745.01	2686.71	356.88	574.19	525.20	817.73	**0.3505**	**0.3785**	**0.3577**
1.5	1745.01	3085.95	356.88	682.01	525.20	958.05	**0.3388**	**0.3779**	**0.3546**
2	1745.01	3470.42	356.88	789.73	525.20	1096.70	**0.3308**	**0.3775**	**0.3524**

Water-Wet (Soi= 0.75) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1699.05	2186.95	365.58	475.16	525.72	669.30	**0.3648**	**0.3748**	**0.3533**
1	1699.05	2186.95	365.58	582.18	525.72	811.43	**0.2231**	**0.3721**	**0.3521**
1.5	1699.05	2186.95	365.58	689.43	525.72	953.33	**0.1607**	**0.3713**	**0.3516**
2	1699.05	2186.95	365.58	800.65	525.72	1539.23	**0.1256**	**0.3731**	**0.4908**

Table 5.14: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the water-wet reservoir (S_{oi}= 0.75).

Water-Wet (Soi= 0.5) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	534.32	715.85	82.83	108.81	483.90	634.66	**0.4046**	**0.3855**	**0.3839**
1	534.32	875.33	82.83	197.22	483.90	772.33	**0.3896**	**0.5800**	**0.3735**
1.5	534.32	1021.77	82.83	217.68	483.90	909.73	**0.3782**	**0.5205**	**0.3697**
2	534.32	1159.52	82.83	221.64	483.90	1048.84	**0.3691**	**0.4559**	**0.3686**

Water-Wet (Soi= 0.5) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	529.57	687.62	82.04	106.47	471.86	618.47	**0.3738**	**0.3732**	**0.3833**
1	529.57	836.06	82.04	113.79	471.86	763.66	**0.3666**	**0.2790**	**0.3821**
1.5	529.57	980.27	82.04	124.74	471.86	906.90	**0.3620**	**0.2576**	**0.3807**
2	529.57	1122.66	82.04	125.16	471.86	1050.24	**0.3590**	**0.2081**	**0.3800**

Water-Wet (Soi= 0.5) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1702.21	2199.71	364.39	473.65	525.82	671.59	**0.3689**	**0.3749**	**0.3567**
1	1702.21	2634.22	364.39	582.08	525.82	814.20	**0.3538**	**0.3740**	**0.3542**
1.5	1702.21	3035.00	364.39	689.88	525.82	955.22	**0.3430**	**0.3732**	**0.3525**

Table 5.15: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the water-wet reservoir (S_{oi}= 0.5).

Oil-Wet (Soi= 0.75) @ day 1									
kd	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	760.27	1226.12	285.52	448.33	456.90	679.86	**0.5507**	**0.5328**	**0.4939**
1	760.27	1808.11	285.52	604.09	456.90	894.36	**0.5795**	**0.5273**	**0.4891**
1.5	760.27	2521.87	285.52	758.56	456.90	1109.40	**0.6070**	**0.5248**	**0.4877**
2	760.27	3413.63	285.52	909.75	456.90	1333.03	**0.6357**	**0.5222**	**0.4895**

Oil-Wet (Soi= 0.75) @ day 300									
kd	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	874.12	1469.26	295.17	445.23	456.55	683.36	**0.5766**	**0.5042**	**0.4984**
1	874.12	2172.35	295.17	592.32	456.55	911.60	**0.5976**	**0.5017**	**0.4992**
1.5	874.12	3005.40	295.17	734.59	456.55	1141.59	**0.6191**	**0.4981**	**0.5001**
2	874.12	3895.38	295.17	871.19	456.55	1370.95	**0.6335**	**0.4939**	**0.5004**

Oil-Wet (Soi= 0.75) @ day 600									
kd	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	980.37	1626.24	295.01	437.24	465.40	693.90	**0.5685**	**0.4909**	**0.4954**
1	980.37	2388.72	295.01	575.07	465.40	921.62	**0.5896**	**0.4870**	**0.4950**
1.5	980.37	3224.40	295.01	708.28	465.40	1147.59	**0.6041**	**0.4829**	**0.4942**
2	980.37	4091.19	295.01	837.48	465.40	1371.34	**0.6134**	**0.4790**	**0.4932**

Table 5.16: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the oil-wet reservoir (S_{oi}= 0.75).

Oil-Wet (Soi= 0.75) @ day 1									
kd	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	760.27	1226.12	285.52	448.33	456.90	679.86	**0.5507**	**0.5328**	**0.4939**
1	760.27	1808.11	285.52	604.09	456.90	894.36	**0.5795**	**0.5273**	**0.4891**
1.5	760.27	2521.87	285.52	758.56	456.90	1109.40	**0.6070**	**0.5248**	**0.4877**
2	760.27	3413.63	285.52	909.75	456.90	1333.03	**0.6357**	**0.5222**	**0.4895**

Oil-Wet (Soi= 0.75) @ day 300									
kd	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	874.12	1469.26	295.17	445.23	456.55	683.36	**0.5766**	**0.5042**	**0.4984**
1	874.12	2172.35	295.17	592.32	456.55	911.60	**0.5976**	**0.5017**	**0.4992**
1.5	874.12	3005.40	295.17	734.59	456.55	1141.59	**0.6191**	**0.4981**	**0.5001**
2	874.12	3895.38	295.17	871.19	456.55	1370.95	**0.6335**	**0.4939**	**0.5004**

Oil-Wet (Soi= 0.75) @ day 600									
kd	mrt_{cons1}	mrt_{part1}	mrt_{cons2}	mrt_{part2}	mrt_{cons3}	mrt_{part3}	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	980.37	1626.24	295.01	437.24	465.40	693.90	**0.5685**	**0.4909**	**0.4954**
1	980.37	2388.72	295.01	575.07	465.40	921.62	**0.5896**	**0.4870**	**0.4950**
1.5	980.37	3224.40	295.01	708.28	465.40	1147.59	**0.6041**	**0.4829**	**0.4942**
2	980.37	4091.19	295.01	837.48	465.40	1371.34	**0.6134**	**0.4790**	**0.4932**

Table 5.17: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the oil-wet reservoir (S_{oi}= 0.65).

Water-Wet (Soi= 0.75) @ day 1						
kd	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	110451.4	127121	74211.91	**0.3469**	**0.2861**	**0.4792**
1	113099.7	127793.8	74365.74	**0.3372**	**0.2836**	**0.4786**
1.5	115004.9	128346.6	74473.49	**0.3303**	**0.2816**	**0.4782**
2	117509.1	128866.4	74637.12	**0.3212**	**0.2797**	**0.4776**

Water-Wet (Soi= 0.75) @ day 600						
kd	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	62460.5	66682.55	63956.9	**0.5221**	**0.5066**	**0.5166**
1	64235.04	68114.96	65615.85	**0.5156**	**0.5014**	**0.5105**
1.5	65793.92	69321.97	67053.75	**0.5099**	**0.4970**	**0.5053**
2	67165.54	70393.22	68292.88	**0.5049**	**0.4931**	**0.5008**

Table 5.18: S_o calculations per layer, obtained from production data, in the case where different tracers are being injected at each connection, in the water-wet reservoir (S_{oi}= 0.75).

Water-Wet (Soi= 0.5) @ day 1						
kd	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	27232.11	5509.985	21744.79	**0.4006**	**0.4799**	**0.4206**
1	28325.5	5741.898	22596.18	**0.3966**	**0.4790**	**0.4175**
1.5	29281.47	5920.081	23348.82	**0.3931**	**0.4784**	**0.4148**
2	30170.06	6053.89	24021.75	**0.3899**	**0.4779**	**0.4123**

Water-Wet (Soi= 0.5) @ day 600						
kd	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o(k=1)}$	$S_{o(k=2)}$	$S_{o(k=3)}$
0.5	57279.32	37251.18	12315.13	**0.2910**	**0.3641**	**0.4551**
1	59769.79	37879.87	12447.42	**0.2819**	**0.3618**	**0.4546**
1.5	61831.47	38402.75	12544.6	**0.2743**	**0.3598**	**0.4542**

Table 5.19: S_o calculations per layer, obtained from production data, in the case where different tracers are being injected at each connection, in the water-wet reservoir (S_{oi}= 0.5).

Oil-Wet (Soi= 0.75) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	63563.01	51850.8	52315.58	**0.5180**	**0.5608**	**0.5591**
1	67587.78	78799.67	53486.64	**0.5033**	**0.4624**	**0.5548**
1.5	70984.39	83594.75	54887.57	**0.4909**	**0.4449**	**0.5497**
2	72897.2	87736.93	56595.52	**0.4840**	**0.4298**	**0.5435**

Oil-Wet (Soi= 0.65) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	42682.73	39884.9	26582.84	**0.4942**	**0.5044**	**0.5530**
1	46699.52	42694.6	27764.55	**0.4796**	**0.4942**	**0.5487**
1.5	50103.63	47432.84	29195.01	**0.4671**	**0.4769**	**0.5435**
2	52033.58	51601.8	30911.49	**0.4601**	**0.4617**	**0.5372**

Table 5.20: S_o calculations per layer, obtained from production data, in the case where different tracers are being injected at each connection, in the oil-wet reservoir.

Water-Wet (Soi= 0.75) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1028.56	1417.96	365.24	471.30	624.59	850.91	**0.4309**	**0.3674**	**0.4202**
1	1028.56	1758.61	365.24	577.74	624.59	1053.46	**0.4151**	**0.3678**	**0.4071**
1.5	1028.56	2076.01	365.24	672.57	624.59	1242.71	**0.4044**	**0.3594**	**0.3975**
2	1028.56	2384.25	365.24	766.10	624.59	1426.23	**0.3972**	**0.3543**	**0.3909**

Water-Wet (Soi= 0.75) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1150.18	1489.88	334.64	430.15	687.15	882.21	**0.3713**	**0.3634**	**0.3621**
1	1150.18	1815.00	334.61	530.27	687.05	1075.03	**0.3663**	**0.3690**	**0.3609**
1.5	1150.18	2125.59	334.61	625.53	687.05	1258.92	**0.3612**	**0.3669**	**0.3569**
2	1150.18	2431.83	334.61	721.16	687.05	1441.58	**0.3578**	**0.3661**	**0.3545**

Water-Wet (Soi= 0.75) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1179.56	1501.70	325.65	422.38	664.81	851.37	**0.3533**	**0.3727**	**0.3595**
1	1179.56	1815.24	325.65	519.95	664.81	1036.18	**0.3502**	**0.3737**	**0.3584**
1.5	1179.56	2123.51	325.65	617.64	664.81	1220.33	**0.3479**	**0.3741**	**0.3578**
2	1179.56	2430.06	325.65	715.30	664.81	1404.71	**0.3464**	**0.3743**	**0.3575**

Table 5.21: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the water-wet reservoir (S_{oi}= 0.75) and z-transmissibility is 0.

Water-Wet (Soi= 0.5) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1125.26	1523.84	339.34	446.56	645.25	875.85	**0.4147**	**0.3872**	**0.4168**
1	1792.22	2621.25	454.46	763.04	495.87	1514.14	**0.3163**	**0.4044**	**0.6725**
1.5	1792.22	3074.10	454.46	895.05	495.87	1781.74	**0.3229**	**0.3926**	**0.6335**
2	1792.22	3512.72	454.46	1024.50	495.87	2039.81	**0.3243**	**0.3854**	**0.6089**

Water-Wet (Soi= 0.5) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1193.85	1553.87	326.54	423.40	681.02	885.69	**0.3762**	**0.3724**	**0.3754**
1	1193.85	1884.78	326.54	518.43	681.02	1078.24	**0.3666**	**0.3701**	**0.3684**
1.5	1193.85	2202.71	326.54	612.42	681.02	1264.17	**0.3604**	**0.3686**	**0.3634**
2	1193.85	2513.84	326.54	706.35	681.02	1447.30	**0.3560**	**0.3677**	**0.3600**

Water-Wet (Soi= 0.5) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	1199.87	1537.51	324.89	420.40	673.02	865.51	**0.3601**	**0.3703**	**0.3639**
1	1199.87	1861.37	324.89	516.18	673.02	1052.92	**0.3554**	**0.3706**	**0.3608**
1.5	1199.87	2176.02	324.89	612.04	673.02	1237.53	**0.3516**	**0.3708**	**0.3586**
2	1199.87	2485.99	324.89	707.94	673.02	1421.61	**0.3489**	**0.3709**	**0.3574**

Table 5.22: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the water-wet reservoir (S_{oi}= 0.5) and z-transmissibility is 0.

Oil-Wet (Soi= 0.75) @ day 1									
kd	mrtcons 1	mrtpart 1	mrtcons 2	mrtpart 2	mrtcons 3	mrtpart 3	So (k=1)	So (k=2)	So (k=3)
0.5	713.42	1120.11	284.04	441.75	474.48	732.47	**0.5327**	**0.5262**	**0.5210**
1	713.42	1541.75	284.04	587.32	474.48	988.80	**0.5373**	**0.5164**	**0.5202**
1.5	713.42	1983.08	284.04	729.54	474.48	1244.81	**0.5426**	**0.5112**	**0.5198**
2	713.42	2445.48	284.04	868.53	474.48	1503.32	**0.5483**	**0.5071**	**0.5202**

Oil-Wet (Soi= 0.75) @ day 300									
kd	mrtcons 1	mrtpart 1	mrtcons 2	mrtpart 2	mrtcons 3	mrtpart 3	So (k=1)	So (k=2)	So (k=3)
0.5	753.91	1175.04	285.29	429.57	488.69	746.75	**0.5277**	**0.5028**	**0.5137**
1	753.91	1616.47	285.29	570.94	488.69	1005.68	**0.5336**	**0.5003**	**0.5141**
1.5	753.91	2078.74	285.29	708.98	488.69	1267.70	**0.5395**	**0.4975**	**0.5152**
2	753.91	2566.16	285.29	843.48	488.69	1532.70	**0.5458**	**0.4945**	**0.5165**

Oil-Wet (Soi= 0.75) @ day 600									
kd	mrtcons 1	mrtpart 1	mrtcons 2	mrtpart 2	mrtcons 3	mrtpart 3	So (k=1)	So (k=2)	So (k=3)
0.5	782.02	1221.79	287.37	426.65	500.73	762.69	**0.5294**	**0.4922**	**0.5113**
1	782.02	1682.42	287.37	562.67	500.73	1028.12	**0.5352**	**0.4893**	**0.5130**
1.5	782.02	2166.38	287.37	694.94	500.73	1295.59	**0.5413**	**0.4860**	**0.5142**
2	782.02	2672.19	287.37	823.65	500.73	1563.23	**0.5472**	**0.4827**	**0.5148**

Table 5.23: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the oil-wet reservoir (S_{oi}= 0.75) and z-transmissibility is 0.

Oil-Wet (Soi= 0.65) @ day 1									
kd	mrtcons 1	mrtpart 1	mrtcons 2	mrtpart 2	mrtcons 3	mrtpart 3	So (k=1)	So (k=2)	So (k=3)
0.5	758.89	1170.78	270.70	419.18	482.20	740.94	**0.5205**	**0.5231**	**0.5176**
1	758.89	1599.91	270.70	564.76	482.20	998.49	**0.5257**	**0.5207**	**0.5171**
1.5	758.89	2050.17	270.70	706.97	482.20	1256.64	**0.5315**	**0.5179**	**0.5171**
2	758.89	2523.51	270.70	845.86	482.20	1517.88	**0.5376**	**0.5151**	**0.5178**

Oil-Wet (Soi= 0.65) @ day 300									
kd	mrtcons 1	mrtpart 1	mrtcons 2	mrtpart 2	mrtcons 3	mrtpart 3	So (k=1)	So (k=2)	So (k=3)
0.5	755.01	1180.68	284.71	428.71	488.64	748.08	**0.5300**	**0.5029**	**0.5150**
1	755.01	1627.95	284.71	569.71	488.64	1009.34	**0.5362**	**0.5003**	**0.5159**
1.5	755.01	2097.33	284.71	707.18	488.64	1274.08	**0.5424**	**0.4973**	**0.5173**
2	755.01	2593.03	284.71	840.91	488.64	1541.58	**0.5490**	**0.4941**	**0.5186**

Oil-Wet (Soi= 0.65) @ day 600									
kd	mrtcons 1	mrtpart 1	mrtcons 2	mrtpart 2	mrtcons 3	mrtpart 3	So (k=1)	So (k=2)	So (k=3)
0.5	785.82	1231.36	286.43	424.94	502.27	766.86	**0.5314**	**0.4916**	**0.5130**
1	785.82	1698.58	286.43	560.02	502.27	1034.73	**0.5374**	**0.4885**	**0.5146**
1.5	785.82	2189.94	286.43	691.34	502.27	1304.12	**0.5436**	**0.4852**	**0.5156**
2	785.82	2702.64	286.43	819.14	502.27	1573.22	**0.5495**	**0.4818**	**0.5160**

Table 5.24: S_o predictions per layer, obtained from mean residence time in the case where different tracers are injected at each connection, over time, in the oil-wet reservoir (S_{oi}= 0.65) and z-transmissibility is 0.

Water-Wet (Soi= 0.75) @ day 1						
kd	WOPT # 1	WOPT # 2	WOPT # 3	So (k=1)	So (k=2)	So (k=3)
0.5	96120.3	96884.76	96422.22	**0.3992**	**0.3964**	**0.3981**
1	97129.73	97957.61	97425.66	**0.3955**	**0.3925**	**0.3944**
1.5	98012.72	98930.17	98320.42	**0.3923**	**0.3890**	**0.3912**
2	98839.41	99857.84	99194.5	**0.3893**	**0.3856**	**0.3880**

Water-Wet (Soi= 0.75) @ day 300						
kd	WOPT # 1	WOPT # 2	WOPT # 3	So (k=1)	So (k=2)	So (k=3)
0.5	96984.84	98920.97	97662.15	**0.3961**	**0.3890**	**0.3936**
1	97866.02	99876.8	98550.34	**0.3928**	**0.3855**	**0.3903**
1.5	98703.95	100758.5	99419.96	**0.3898**	**0.3823**	**0.3872**
2	99531.72	101609.3	100261.1	**0.3868**	**0.3792**	**0.3841**

Water-Wet (Soi= 0.75) @ day 600						
kd	WOPT # 1	WOPT # 2	WOPT # 3	So (k=1)	So (k=2)	So (k=3)
0.5	97580.97	100807.8	98576.59	**0.3939**	**0.3821**	**0.3902**
1	98433.09	101673.8	99446.08	**0.3908**	**0.3789**	**0.3871**
1.5	99263.35	102460.3	100287.2	**0.3877**	**0.3761**	**0.3840**
2	100087.2	103162.9	101098.3	**0.3847**	**0.3735**	**0.3810**

Table 5.25: S_o calculations per layer, obtained from production data use, in the case where different tracers are being injected in each connection, in the water-wet reservoir (S_{oi}= 0.75), for z-transmissibility equal to 0.

Water-Wet (Soi= 0.5) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	27276.54	28437.85	27681.97	**0.4005**	**0.3962**	**0.3990**
1	28279.43	29396.39	28631.96	**0.3968**	**0.3927**	**0.3955**
1.5	29136.79	30319.35	29507.02	**0.3937**	**0.3894**	**0.3923**
2	29967.03	31198.95	30362.18	**0.3906**	**0.3861**	**0.3892**

Water-Wet (Soi= 0.5) @ day 300						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	27838.37	29810.87	28469.11	**0.3984**	**0.3912**	**0.3961**
1	28739.25	30755.2	29364.94	**0.3951**	**0.3878**	**0.3928**
1.5	29584.33	31656.12	30222.99	**0.3920**	**0.3845**	**0.3897**
2	30410.38	32503.11	31066.28	**0.3890**	**0.3814**	**0.3866**

Water-Wet (Soi= 0.5) @ day 600						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	28318.03	31375.16	29252.86	**0.3967**	**0.3855**	**0.3932**
1	29185.17	32256.38	30128.6	**0.3935**	**0.3823**	**0.3900**
1.5	30024.18	33083.69	30974.46	**0.3904**	**0.3793**	**0.3870**
2	30838.5	33822.57	31793.24	**0.3875**	**0.3766**	**0.3840**

Table 5.26: S_o calculations per layer, obtained from production data, in the case where different tracers are being injected at each connection, in the water-wet reservoir (S_{oi}= 0.5), for z-transmissibility equal to 0.

Oil-Wet (Soi= 0.65) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	32729.13	34130.76	33235.34	**0.5306**	**0.5254**	**0.5287**
1	34641.96	36264.71	35214.57	**0.5236**	**0.5177**	**0.5215**
1.5	36443.24	38032.19	36996.68	**0.5170**	**0.5112**	**0.5150**
2	38235.87	39414.57	38557.52	**0.5105**	**0.5062**	**0.5093**

Oil-Wet (Soi= 0.65) @ day 300						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	33714.45	37049.73	34865.61	**0.5270**	**0.5148**	**0.5228**
1	35590.24	38776.62	36700.16	**0.5201**	**0.5085**	**0.5161**
1.5	37287.48	40228.41	38313.68	**0.5139**	**0.5032**	**0.5102**
2	38781.17	41450	39698.19	**0.5085**	**0.4987**	**0.5051**

Oil-Wet (Soi= 0.65) @ day 600						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	34685.12	39161.5	36293.07	**0.5234**	**0.5071**	**0.5175**
1	36477.9	40591.21	37952.81	**0.5169**	**0.5019**	**0.5115**
1.5	38061.84	41796.41	39391.47	**0.5111**	**0.4975**	**0.5062**
2	39456.27	42866.41	40649.1	**0.5060**	**0.4936**	**0.5017**

Table 5.27: S_o calculations per layer, obtained from production data, in the case where different tracers are being injected at each connection, in the oil-wet reservoir (S_{oi}= 0.65), for z-transmissibility equal to 0.

Oil-Wet (Soi= 0.75) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	60286.54	61331.27	60693.56	**0.5300**	**0.5262**	**0.5285**
1	62178.89	63482.39	62662.07	**0.5231**	**0.5183**	**0.5213**
1.5	63968.25	65383.99	64875.86	**0.5165**	**0.5114**	**0.5132**
2	65574.27	66954.5	66049.82	**0.5107**	**0.5057**	**0.5090**

Oil-Wet (Soi= 0.75) @ day 300						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	61501.93	65295.85	62519.14	**0.5255**	**0.5117**	**0.5218**
1	63330.5	66217.58	64363.59	**0.5189**	**0.5083**	**0.5151**
1.5	65009.14	67707.27	65952.81	**0.5128**	**0.5029**	**0.5093**
2	66478.04	68960.82	67335.76	**0.5074**	**0.4983**	**0.5043**

Oil-Wet (Soi= 0.75) @ day 600						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	S_o (k=1)	S_o (k=2)	S_o (k=3)
0.5	62460.5	66682.55	63956.9	**0.5221**	**0.5066**	**0.5166**
1	64235.04	68114.96	65615.85	**0.5156**	**0.5014**	**0.5105**
1.5	65793.92	69321.97	67053.75	**0.5099**	**0.4970**	**0.5053**
2	67165.54	70393.22	68292.88	**0.5049**	**0.4931**	**0.5008**

Table 5.28: S_o calculations per layer, obtained from production data, in the case where different tracers are being injected at each connection, in the oil-wet reservoir (S_{oi}= 0.75), for z-transmissibility equal to 0.

Water-Wet (Soi= 0.75) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	93080.86	14579.25	84253.68	**0.4016**	**-0.3141**	**0.4346**
1	94207.69	14813.48	85115.39	**0.3974**	**-0.3312**	**0.4314**
1.5	95202.98	15008.27	85877.09	**0.3936**	**-0.3454**	**0.4286**
2	96082.59	15123.82	86572.7	**0.3904**	**-0.3539**	**0.4260**

Table 5.29: S_o calculations per layer, obtained from production data use, in the case where different tracers are being injected in each connection, in the water-wet thief zone reservoir (S_{oi}= 0.75).

Water-Wet (Soi= 0.75) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	527.59	701.42	117.72	174.32	477.23	624.85	**0.3972**	**0.4902**	**0.3822**
1	527.59	850.69	117.72	332.34	477.23	759.88	**0.3798**	**0.6458**	**0.3720**
1.5	527.59	990.96	117.72	385.07	477.23	896.55	**0.3693**	**0.6022**	**0.3694**
2	527.59	1127.85	117.72	421.65	477.23	1035.26	**0.3626**	**0.5635**	**0.3689**

Table 5.30: S_o calculations per layer, obtained from mean residence time, in the case where different tracers are being injected in each connection, in the water-wet thief zone reservoir (S_{oi}= 0.75).

Water-Wet (Soi= 0.75) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	92872.79	4796.457	92855.58	**0.4024**	**0.3999**	**0.4024**
1	93937.2	4851.141	93919.93	**0.3984**	**0.3959**	**0.3985**
1.5	94820.19	4903.18	94802.38	**0.3951**	**0.3921**	**0.3951**
2	95656.69	4950.682	95638.09	**0.3920**	**0.3887**	**0.3920**

Table 5.31: S_o calculations per layer, obtained from production data use, in the case where different tracers are being injected in each connection, in the water-wet thief zone reservoir (S_{oi}= 0.75) for 0 z-transmissibility.

Water-Wet (Soi= 0.75) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	508.11	689.54	46.39	60.80	507.87	689.33	**0.4166**	**0.3833**	**0.4168**
1	508.11	856.41	46.39	73.27	507.87	856.28	**0.4067**	**0.3669**	**0.4069**
1.5	508.11	1015.42	46.39	84.58	507.87	1015.36	**0.3996**	**0.3544**	**0.3998**
2	508.11	1170.17	46.39	95.14	507.87	1170.17	**0.3945**	**0.3444**	**0.3947**

Table 5.32: S_o calculations per layer, obtained from mean residence time, in the case where different tracers are being injected in each connection, in the water-wet thief zone reservoir (S_{oi}= 0.75) for 0 z-transmissibility.

Oil-Wet (Soi= 0.65) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	37085.21	70561.62	22361.86	**0.5112**	**-4.5003**	**0.5663**
1	39572.99	73910.66	22958.17	**0.5019**	**-4.7447**	**0.5641**
1.5	41899.16	76234.76	23378	**0.4932**	**-4.9143**	**0.5625**

Table 5.33: S_o calculations per layer, obtained from production data use, in the case where different tracers are being injected in each connection, in the oil-wet thief zone reservoir (S_{oi}= 0.65).

Oil-Wet (Soi= 0.65) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	3612.70	6328.92	183.16	264.20	3035.31	4951.99	**0.6006**	**0.4695**	**0.5581**
1	3612.70	9673.14	183.16	349.87	3035.31	6717.51	**0.6265**	**0.4765**	**0.5481**
1.5	3612.70	13359.12	183.16	434.16	3035.31	8548.98	**0.6427**	**0.4774**	**0.5477**
2	3612.70	16978.85	183.16	505.71	3035.31	10240.08	**0.6491**	**0.4682**	**0.5427**

Oil-Wet (Soi= 0.65) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	3997.69	6727.41	179.99	249.39	3349.37	5103.47	**0.5773**	**0.4354**	**0.5116**
1	3997.69	10134.05	179.99	346.25	3349.37	6861.05	**0.6055**	**0.4802**	**0.5118**
1.5	3997.69	13672.95	179.99	451.67	3349.37	8619.49	**0.6174**	**0.5016**	**0.5120**
2	3997.69	17181.77	179.99	536.91	3349.37	10216.16	**0.6225**	**0.4979**	**0.5062**

Oil-Wet (Soi= 0.65) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	4105.28	6928.87	200.07	281.23	3384.33	5114.87	**0.5791**	**0.4479**	**0.5056**
1	4105.28	10334.39	200.07	361.27	3384.33	6871.61	**0.6028**	**0.4462**	**0.5075**
1.5	4105.28	13805.41	200.07	440.20	3384.33	8580.89	**0.6117**	**0.4445**	**0.5058**
2	4105.28	17264.01	200.07	518.11	3384.33	10125.17	**0.6158**	**0.4428**	**0.4990**

Table 5.34: S_o calculations per layer, obtained from mean residence time, in the case where different tracers are being injected in each connection, in the oil-wet thief zone reservoir (S_{oi}= 0.65).

Oil-Wet (Soi= 0.65) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	396.07	632.95	35.92	49.92	396.14	632.97	**0.5447**	**0.4380**	**0.5446**
1	396.07	879.90	35.92	66.23	396.14	879.96	**0.5499**	**0.4576**	**0.5498**
1.5	396.07	1130.00	35.92	79.80	396.14	1130.11	**0.5526**	**0.4488**	**0.5526**
2	396.07	1381.74	35.92	92.78	396.14	1381.92	**0.5544**	**0.4418**	**0.5544**

Oil-Wet (Soi= 0.65) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	437.31	687.99	30.85	42.48	437.32	688.06	**0.5341**	**0.4297**	**0.5342**
1	437.31	941.22	30.85	53.92	437.32	941.35	**0.5354**	**0.4279**	**0.5354**
1.5	437.31	1196.31	30.85	65.22	437.32	1196.51	**0.5364**	**0.4262**	**0.5365**
2	437.31	1453.56	30.85	76.35	437.32	1453.85	**0.5374**	**0.4244**	**0.5375**

Oil-Wet (Soi= 0.65) @ day 600									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	466.86	721.33	27.40	36.76	466.90	721.42	**0.5216**	**0.4058**	**0.5216**
1	466.86	978.60	27.40	46.01	466.90	978.77	**0.5229**	**0.4045**	**0.5230**
1.5	466.86	1237.76	27.40	55.21	466.90	1238.01	**0.5240**	**0.4036**	**0.5240**
2	466.86	1498.03	27.40	64.36	466.90	1498.38	**0.5248**	**0.4028**	**0.5248**

Table 5.35: S_o calculations per layer, obtained from mean residence time, in the case where different tracers are being injected in each connection, in the oil-wet thief zone reservoir (S_{oi}= 0.65) for 0 z-transmissibility.

Oil-Wet (Soi= 0.65) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	25033.36	1643.424	25033.36	**0.5563**	**0.5300**	**0.5563**
1	26387.58	1721.819	26387.58	**0.5512**	**0.5243**	**0.5512**
1.5	27698.29	1786.701	27672.59	**0.5463**	**0.5196**	**0.5464**
2	28963.91	1839.246	28936.62	**0.5416**	**0.5158**	**0.5417**

Oil-Wet (Soi= 0.65) @ day 300						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	26226.71	2079.441	26202.62	**0.5518**	**0.4982**	**0.5519**
1	27554.46	2110.09	27528.54	**0.5469**	**0.4960**	**0.5470**
1.5	28817.68	2138.951	28805.52	**0.5421**	**0.4939**	**0.5422**
2	30018.98	2161.742	29990.03	**0.5376**	**0.4922**	**0.5377**

Oil-Wet (Soi= 0.65) @ day 600						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	27343.85	2293.955	27318.25	**0.5477**	**0.4826**	**0.5477**
1	28644.4	2310.54	28617.11	**0.5428**	**0.4814**	**0.5429**
1.5	29852.6	2326.483	29823.87	**0.5383**	**0.4802**	**0.5384**
2	30984.43	2341.837	30954.49	**0.5340**	**0.4791**	**0.5341**

Table 5.36: S_o calculations per layer, obtained from production data use, in the case where different tracers are being injected in each connection, in the oil-wet thief zone reservoir (S_{oi}= 0.65) for 0 z-transmissibility.

Water-Wet (Soi= 0.5) @ day 1									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	534.32	715.85	82.83	108.81	483.90	634.66	**0.4046**	**0.3855**	**0.3839**
1	534.32	875.33	82.83	197.22	483.90	772.33	**0.3896**	**0.5800**	**0.3735**
1.5	534.32	1021.77	82.83	217.68	483.90	909.73	**0.3782**	**0.5205**	**0.3697**
2	534.32	1159.52	82.83	221.64	483.90	1048.84	**0.3691**	**0.4559**	**0.3686**

Water-Wet (Soi= 0.5) @ day 300									
k_d	$mrt_{cons\,1}$	$mrt_{part\,1}$	$mrt_{cons\,2}$	$mrt_{part\,2}$	$mrt_{cons\,3}$	$mrt_{part\,3}$	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	534.32	715.85	82.83	108.81	483.90	634.66	**0.4046**	**0.3855**	**0.3839**
1	534.32	875.33	82.83	197.22	483.90	772.33	**0.3896**	**0.5800**	**0.3735**
1.5	534.32	1021.77	82.83	217.68	483.90	909.73	**0.3782**	**0.5205**	**0.3697**
2	534.32	1159.52	82.83	221.64	483.90	1048.84	**0.3691**	**0.4559**	**0.3686**

Table 5.37: S_o calculations per layer, obtained from mean residence time, in the case where different tracers are being injected in each connection, in the water-wet thief zone reservoir (S_{oi}= 0.5).

Water-Wet (Soi= 0.5) @ day 1						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	25033.36	1643.424	25033.36	**0.4063**	**0.3800**	**0.4063**
1	26387.58	1721.819	26387.58	**0.4012**	**0.3743**	**0.4012**
1.5	27698.29	1786.701	27672.59	**0.3963**	**0.3696**	**0.3964**
2	28963.91	1839.246	28936.62	**0.3916**	**0.3658**	**0.3917**

Water-Wet (Soi= 0.5) @ day 300						
k_d	WOPT # 1	WOPT # 2	WOPT # 3	$S_{o\,(k=1)}$	$S_{o\,(k=2)}$	$S_{o\,(k=3)}$
0.5	26226.71	2079.441	26202.62	**0.4018**	**0.3482**	**0.4019**
1	27554.46	2110.09	27528.54	**0.3969**	**0.3460**	**0.4119**
1.5	28817.68	2138.951	28805.52	**0.3921**	**0.3439**	**0.4078**
2	30018.98	2161.742	29990.03	**0.3876**	**0.3422**	**0.4041**

Table 5.38: S_o calculations per layer, obtained from production data use, in the case where different tracers are being injected in each connection, in the water-wet thief zone reservoir (S_{oi}= 0.5).

6. Naturally Fractured Reservoirs

A significant amount of the produced hydrocarbons originates from naturally fractured reservoirs. Four types of naturally fractured reservoirs can be classified according to Nelson (2001). If fractures exhibit both high porosity (capacity) and permeability they are classified as type 1. If the matrix exhibits sufficient storage capacity and the flow is conducted through the high permeable fractures, the system is identified as of type 2. If matrix permeability is equivalent to that of the fractures, then the system is of type 3, whereas in type 4 fractures hinder the flow due to barriers of minerals etc.

Warren and Root (1963) were the first to introduce the concept of dual porosity, as a general model that could possibly incorporate many different cases of naturally fractured reservoirs. The modelling of a fractured reservoir into a dual porosity one is illustrated in **Fig. 6.43** (*Kazemi et al., 1976*). Over the years dual porosity model was enriched and numerous versions of the latter have been devised. Nowadays, not only all commercial simulators are able to perform dual porosity runs, but in fact the latter is the standard method for naturally fractured reservoir simulation. Discrete fracture models are implemented when the former's capability of generating realistic results is vague, or when the fracture network is not adequately described by the dual porosity model.

If the matrix blocks are not connected between each other but only through the fracture blocks (matrix-to- matrix block transmissibility is 0) then the system is referred to as dual porosity, single permeability (type 1 according to Nelson). If however, flow takes place across matrix blocks (matrix- to – matrix block transmissibility is positive) the system is called dual porosity, dual permeability.

Apart from imbibition (water flooding) other chief recovery mechanisms in dual porosity reservoirs are: *Gravity Drainage/ Imbibition* (fluid exchange between the matrix and the fractures due to gravity, Technical description) and *Viscous Displacement* (which is the movement of a fluid when a pressure differential is applied; through the fracture and towards the production well). Since the main purpose of this project is the investigation of interwell tracer tests, only the case of water flooding was examined.

In a dual porosity run, a reduplicated over the z axis grid is requested by ECLIPSE, where the top-half represents the matrix and the bottom-half the fractures. Apart from the porosity and the relative permeability values for both the matrix and the fractures, a factor called Sigma or Kazemi in its simple form, should be introduced. Initially introduced by Warren and Root (1963) sigma factor is a shape factor that is also used as a multiplier in the transmissibility calculations. The most typical value of Sigma Factor that is the standard value in commercial simulators was devised by Kazemi *(Kazemi et al. 1976*):

$$\sigma = 4\left[\frac{1}{{L_{mx}}^2} + \frac{1}{{L_{my}}^2} + \frac{1}{{L_{mz}}^2}\right]$$

Where L_{mx}, L_{my}, L_{mz} denote the matrix rather than the simulation grid block size. The former is a physical property of the reservoir, and depends on reservoir rock. According to the latter value, the spacing of the fractures is attained automatically by ECLIPSE (*Lalehrokh, 2005*). For instance, for a 0.12 sigma factor value that represents a 10x10x10 ft^3 matrix block, the fractures are introduced every 10 ft. across all directions. Hence, for a sufficient dual porosity model the simulation (total) grid size should be greater than the matrix one, whereas the elemental grid block should be equal or smaller than the matrix block. Similarly, the aperture of the fractures is given implicitly through fracture porosity.

Throughout the years, several versions of the sigma factor have been devised depending on matrix geometry or weighted by absolute permeability values *(Kai and Pao, 2013)*. Their application should be examined for each particular study case, not least in terms of a history matching process in which it can be easily determined which factor yields the best results. In this project the simple sigma factor of Kazemi was used.

6.1. Dual Porosity Model

In the dual porosity model, a porosity value of 0.002 was used as far as fractures are concerned whereas a 0.15 value was given to the matrix. From a mathematical point of view the need for very small fracture porosity can be ascertained by the way a dual porosity model is defined in ECLIPSE. What ECLIPSE requests for a dual porosity run is double the grid size in the z direction. So for reservoir dimensions of 20x20x3 with equivalent grid block size 5ftx5ftx5ft for instance, a 20x20x6 grid will be generated with matrix and fracture blocks of the same size, where the latter are overlaid by the former. Fracture spacing is accomplished through the introduction of sigma factor, as previously described. Still, fracture cells are extremely big. For the most part fractures' aperture is at the order of mm-cm (*Lake and Carrol, 1986*) while in this case it is many orders of magnitude greater. Apart from its geological meaning (as a secondary porosity) porosity is a means to reduce fractures' opening. A high porosity value would simply mean than in the fracture blocks – which are comparable with the corresponding matrix ones, in terms of size – the OOIP would exhibit an abnormally high value, so that enhanced oil production would have been attained. But this implication would have been utterly wide of the mark if the fractures are not supposed to be the source of hydrocarbons (although the may contain some quantity) but the conduit of their flow. Therefore, purely mathematically, a small fracture porosity value states exactly that the storage capacity of fractures is limited by virtue of their small aperture. In fact, matrix and fracture size is considered to be the same from ECLIPSE, which can be realised from the transmissibility calculations. By introducing a small fracture porosity, the fracture storage capacity is reduced.

The input of the dual porosity run is presented in **Table 6.1**. For a matrix block of 10ft.x10ft.x10ft. (equivalently, Kazemi factor equal to 0.12) and simulation block of the same size with grid dimensions 20x20x3, in total 1200 matrix blocks and an equal number of fracture blocks will be generated. Fracture permeability over the x and y direction was set 10^4 times greater than the matrix one, whereas z-permeability is equal for both matrix and fracture.

In a dual porosity model, well completions can only be set at fracture cells. Therefore, water is being injected within the fractures and is produced from fracture cells as well. The volume of oil that used to live within the matrix is produced through fractures as well. In **Fig. 6.1** conservative tracer responses are presented for all three fracture connections. Since no matrix completions exist in reality, tracers are produced solely through fractures. Due to the extremely high permeability value of fractures, the velocity of tracer is increased, and as a result a breakthrough after a few days since injection is observed. Due to the positive fracture z-permeability value and gravity (gravitational segregation), water that is injected at the topmost connection may descent to the middle and bottommost one. For 1 day slug period of dimensionless concentration equal to 1, the area of the field response (**Fig. 6.2**) should be equal to 1. If the area is calculated in a spreadsheet, it exhibits a value higher than 1 (approximately 1.12). This would imply that slug concentration was in reality higher. However, due to the extreme velocity value – the diagonal is approximately 280 ft. and breakthrough occurs at 8 days, that is 35 ft/day- dispersion is broad thereby affecting the results. The difference with regards to breakthrough times of tracers per connection could illustrate that some water does penetrate the matrix and displaces oil which is produced through fractures. By virtue of the penetration and the subsequent displacement this difference in arrivals occurs.

In order to assert this fact the oil saturation variation for the entire grid should be examined **(Figs. 6.3-6.7**). From those plot it can be inferred, that water penetrates the matrix and gradually displaces oil from the very first day of injection. Production occurs faster in the bottom layer as explained before. The volume of oil that used to live in the fractures is instantaneously produced due to the high absolute permeability of the fractures, whereas the displacement process within the matrix is slower. Those implications could not have been made without the visual tools that a commercial simulator such as ECLIPSE provides. Although closer to reality responses were obtained through UTCHEM, a 'broader' picture is obtained from a commercial simulator. At any rate only single-phase flow models of dual porosity can be hitherto conducted in UTCHEM.

Similarly, the conservative tracer concentration throughout the grid for the same time intervals are presented in **Figs. 6.8- 6.10**. These point towards the same implications. The majority of the injected slugs is produced instantaneously through fractures. A smaller proportion of the slug penetrates the matrix alongside water. In this process of penetration, oil displacement and production occurs faster in the bottom layer. The dimensionless concentration of the tracers that are not instantly produced through fractures is rather small, so that it cannot be identified that such a phenomenon takes place from the original producer plots (Dimensionless Concentration vs Time).

6.2. Dual Permeability Model

The same model (**Table 6.1**) was performed, this time for a dual porosity dual permeability run. Connections can be placed at all layers (both fracture and matrix) and matrix to matrix block transmissibility values are calculated.

Cross sections of oil saturation changes for various time intervals are presented in **Figs. 6.11- 6.15**. The corresponding conservative tracer concentrations are presented in **Figs. 6.16- 6.18**. Those plots indicate infinitesimal differences with the dual porosity model. The reason is the very small value of absolute matrix permeability, compared to that of fractures. The major conduit of oil that lies within the matrix, is the fracture system. Hence, matrix to matrix flow, although it exists in a dual permeability model, its contribution to production is ambiguous.

In **Fig. 6.19** the conservative tracer response in the producer is illustrated, as observed within matrix connections. The first peak observed amongst all connections, is related to fractures themselves. From that point on, concentration is decaying but it remains higher than zero, within the detection limits. This type of behaviour underlies the slow movement of fluids that takes place in between matrix blocks. If the average (field) concentration of the same tracer is examined (**Fig. 6.20**), this behaviour cannot be seen, for it is overshadowed by the rapid fracture response. For higher matrix permeability values, the matrix to matrix flow would have been facilitated, and its occurrence would have been possibly clear from the field tracer response. The fact that, tracer responses exhibit different maximum values is associated with the broader production in the bottom layer (layer 3). Since injected water flows downwards from the top to the bottom layer, along with it some amount of tracer also follows this trend. Hence, a quantity of tracer originally injected at the top layer eventually flows across the bottom one, leading to such type of concentration curves. In the bottom layer the injected slug concentration seems greater than the topmost one.

For such a small matrix permeability (10.000 times smaller than the fracture one) the dual porosity model sufficiently describes the system, save the tracer response. Dual permeability models are much more expensive in terms of computational time, compared to dual porosity ones. Hence, in order to save up computational time one could readily use the dual porosity model.

6.3. Discrete Fracture Model

The terminology of Discrete Fracture modelling implies that the user can explicitly generate the fracture network rather than using a predetermined model such as the dual porosity one. If the orientation of the fractures does not align with dual porosity's fracture network, an explicit fracture model would be probably required. Similarly, if history matching results do not comply with a dual porosity and/or permeability model, a discrete fracture model should be tested.

In this case, a discrete fracture model is generated similar to the dual porosity model, as a means of comparison. The data set of the dual permeability model is presented in **Table 6.2.** In fact it is the same as the one used previously, yet with smaller grid size. All other properties such as matrix block size were left intact. The same input was used in the discrete fracture modelling. It has to be stated at this point, that generating an explicit fracture model identical to the dual porosity one was not intended, and at any rate it would have been of no use. Rather than that, a similar model was generated in order to demonstrate their differences. Moreover, the dual permeability model was used in order to highlight the differences in tracer responses between the two models. Although the dual porosity model could have been used, the obscureness of tracer flow within the matrix renders their usage pointless.

In terms of the discrete fracture model, matrix block was set at 4.625x4.625x4.625 ft^3. Hence, every two blocks in every direction, two fractures are placed. Their aperture was selected at 0.5 ft., so that the reservoir size is equal in both models. For a given wellbore radius value of 0.3333 ft. such fracture opening is the smallest that may be used. The procedure of generating the explicit fractures can be seen from the ECLIPSE code of discrete fracture model (**Appendix B**).

At that point, after a relatively small fracture opening has been defined, fracture porosity values should be determined. If the same value of the dual porosity model is being utilised it is certain that simulation will eventually crash (reservoir pressure is increasing abnormally and equilibrium is not satisfied). Since fracture size has been already set at a small value there is no point in maintaining a small porosity value. A much greater fracture porosity value needs to be selected here in order to generate an equivalent model. Therefore, a fracture porosity value of 0.1 was selected. The only difference regarding the fracture network is that the fractures that are located at the edges of the grid were not inserted in the explicit fracture model.

The conservative tracer responses for both systems are presented in **Fig. 6.21** (matrix connection) and **Fig. 6.22** (average response). From the first plot it can be deduced, that the matrix-to-matrix block flow is greater with regards to the dual permeability model, by virtue of the greater 'tail response' at late times in comparison with the discrete model. As it will be shown from transmissibility calculations, only the matrix-fracture transmissibility is different between the dual permeability and the explicit fracture model. For both models, tracer concentration remains positive even at late times which indicates the slow matrix to matrix flow. The latter however, is facilitated in the dual permeability model. Therefore, in order to attain the same number of produced barrels of oil in the discrete fracture model, injection period should be prolonged. The average concentration response indicates an earlier peak in the dual permeability model which points towards that flow across the fractures is faster that the explicit fracture model.

From the oil saturation plots for both the discrete fracture model (**Figs. 6.23- 6.27**) and the dual permeability model (**Figs. 6.28- 6.32**) those implications are corroborated. The ongoing production of oil occurs faster in the dual permeability model. Although both systems exert the same absolute permeability values for both the matrix and the fractures (in which all the OOIP is produced instantly) as well, the injected water displaces oil in the matrix slower in the explicit model than the dual permeability one. As a result tracers flow faster in the matrix and the fractures as well, in the dual permeability model (**Figs. 6.33- 6.37**) while concerning the discrete fracture model **(Figs. 6.38- 6.42**) their flow is retarded. In the dual permeability model after 1 day of injection, the injected slug is more advanced in comparison with the discrete fracture model (Fig.6.33 and 6.38).

Normally, a secondary peak should have been observed in the tracer responses at the production well (**Fig. 6.21**). Instead, a constant concentration slightly higher than zero is observed for both models at later times. The latter is greater with regards to the dual permeability model. Due to small matrix permeability and the consequent small transmissibility value the velocity of the conservative tracer that flows within the matrix is close to 0. Again the latter is higher in the dual permeability model. By virtue of such a small velocity, diffusion is the determining factor, so that a peak cannot be really distinguished. For a high matrix permeability value a secondary peak could have been easily determined graphically, as tracer velocity would have increased within the matrix and subsequently diffusion effects less broad.

The main difference between the two models is the ease at which flow in the matrix takes place regarding the dual permeability model. Reservoir and grid properties are the same for both models. Therefore, transmissibility calculations should be examined for both cases. The matrix-fracture transmissibility in the dual porosity/permeability model is calculated as follows:

$$TRAN(X_i)_{dual\ perm} = CDARCY * K * V_{bulk} * \sigma$$

$CDARCY$ is the Darcy's constant depending on the unit system, K is the absolute permeability over the x direction, V_b is the bulk volume of the i block, and σ is the Kazemi factor. Similarly, transmissibility across the other directions can be calculated.

As far as the discrete fracture model is concerned, matrix-fracture transmissibility over the X direction can be calculated;

$$TRAN(X_i)_{discrete} = \frac{CDARCY * TMLTX_i * A * DIPC}{B}$$

$TMLTX_i$ is the transmissibility multiplier which is 1 in the entire grid, DIPC is a dip correction (equal to 1 in this case).

$$A = \frac{DX_j * \ DY_i * \ DZ_i * RNTG_i + \ DX_i * \ DY_j * \ DZ_j * RNTG_j}{DX_i + DX_j}$$

Where $RNTG$ is the net to gross ratio and *DX, DY, DZ* are the corresponding grid block dimensions. The harmonic average permeability *B* is expressed as:

$$B = \frac{(\frac{DX_i}{PERMX_i} + \frac{DX_j}{PERMX_j})}{2}$$

In case of a 10x10x10 ft^3 matrix block for both dual permeability and explicit fracture model, the ratio of the two models' transmissibility yields:

$$\frac{TRAN(X_i)_{dual\ perm}}{TRAN(X_i)_{discrete}} = 8$$

Matrix-fracture transmissibility is 8 times greater in the dual permeability model compared to that of the discrete fracture model. Matrix-matrix block transmissibility is the same for both models. However, due to the increased value of matrix-fracture transmissibility the penetration of water in the matrix and the consequent displacement of oil is evolving slower in the explicit fracture model.

Since matrix-matrix block transmissibility is the same for both models, the 'tail' of the tracer concentration at late times can be realised (**Fig. 6.21**). The very low value of transmissibility leads to a very low velocity and a diffusive response. In the dual permeability model, the very value of concentration is greater because fracture-matrix transmissibility is greater.

The application of each model should be examined for every specific problem. What is more, through transmissibility multipliers the matrix-fracture transmissibility can be manipulated, so that both models may provide similar results.

Moreover, tracer velocity within the fracture network seems to be higher in the dual permeability model (**Fig. 6.22**). As already explained velocity cannot be easily calculated. Let us approximated water velocity at the first time step, at the injection well:

$$u_{water} = \frac{Q^{r.c}\, B_w\, f_w}{A\, \varphi\, (1 - S_{or})}$$

At the first time step all terms are equal except for the product of cross sectional area with porosity. In fact, this product is higher in the dual permeability model. Therefore, the velocity in the dual permeability model should naturally be smaller than that of the explicit fracture model. At the initialisation of the problem conducted by ECLIPSE in order to satisfy pressure governing equation, all the oil that used to live within the fractures is considered to have been produced. Therefore, the fractional flow of water is equal to 1 in the dual permeability model from the very first day, whereas in the discrete fracture model it exhibits a very small value. Eventually, water velocity is higher in terms of the dual permeability model.

Numerical techniques were not used in naturally fractured reservoir cases. The extremely high velocity within the fracture system and the diffusive response of the matrix system render the implementation of numerical models fruitless.

Figures of Chapter 6

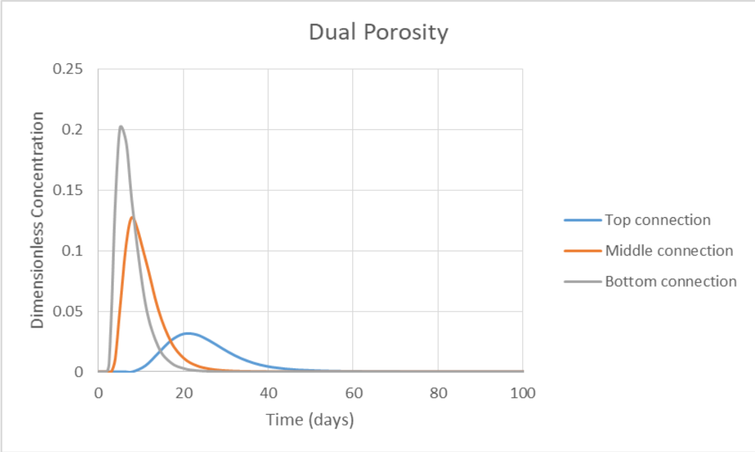

Figure 6.1: Conservative tracer response in all three fracture connections, for a dual porosity run.

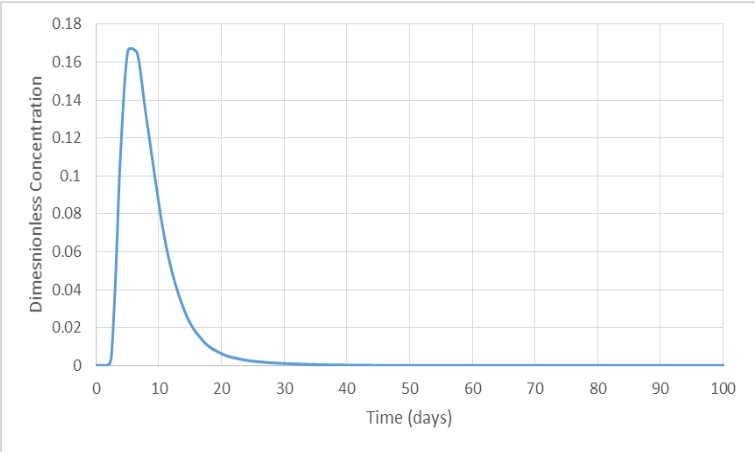

Figure 6.2: Conservative tracer response average (field) response, for a dual porosity run.

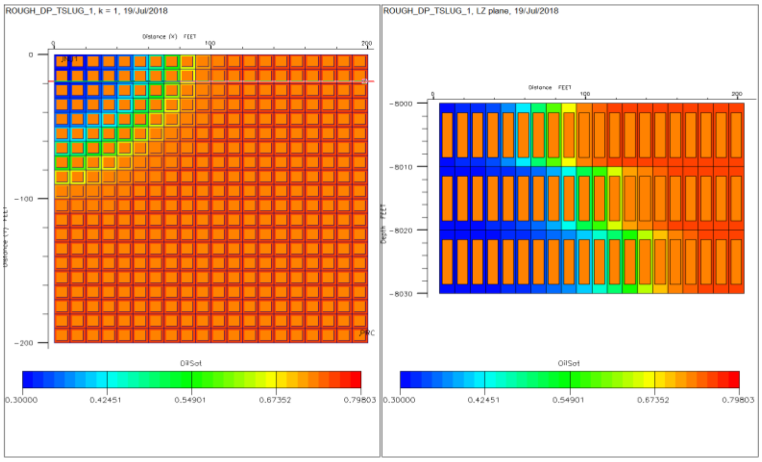

Figure 6.3: Cross-section plot of oil saturation after one day of injection.

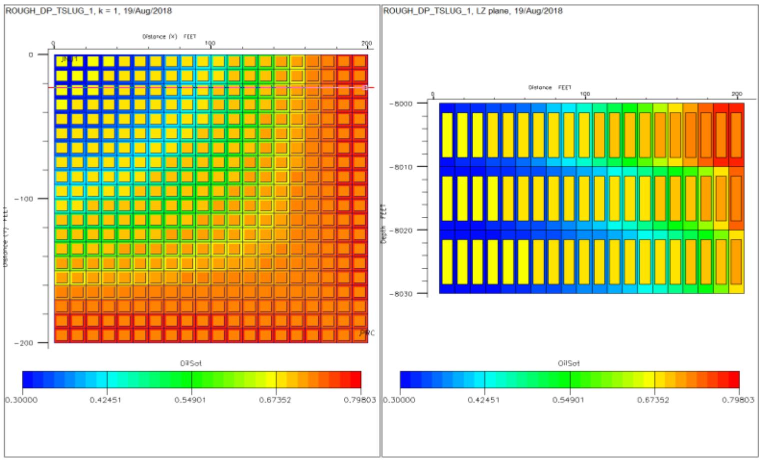

Figure 6.4: Cross-section plot of oil saturation after one month of injection.

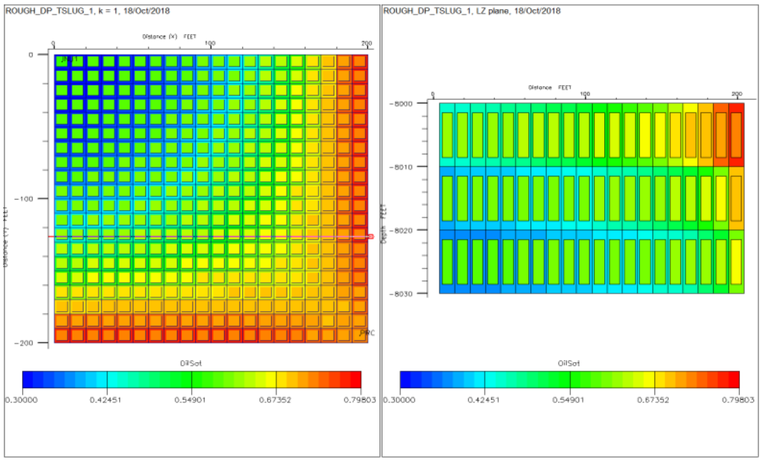

Figure 6.5: Cross-section plot of oil saturation after 3 months of injection.

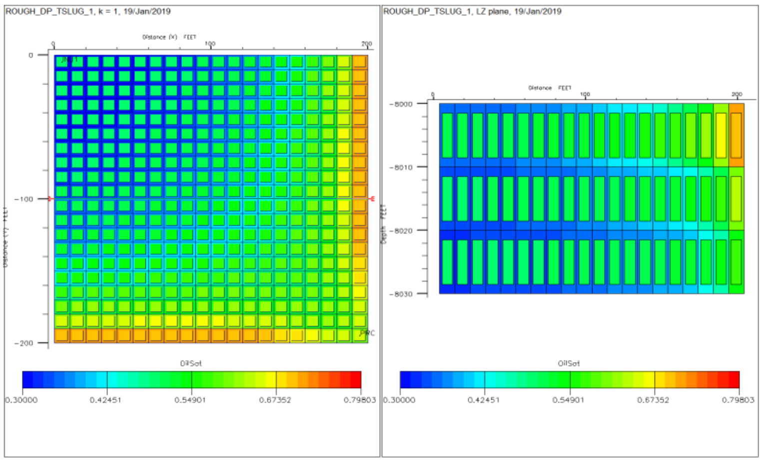

Figure 6.6: Cross-section plot of oil saturation after 6 months of injection.

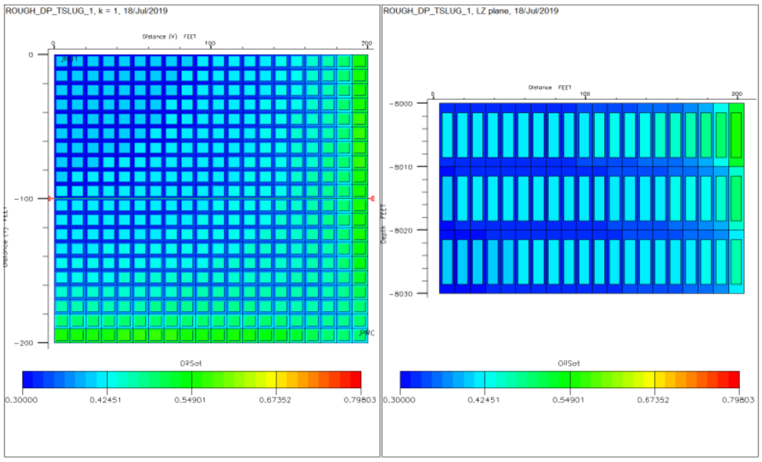

Figure 6.7: Cross-section plot of oil saturation after one year of injection.

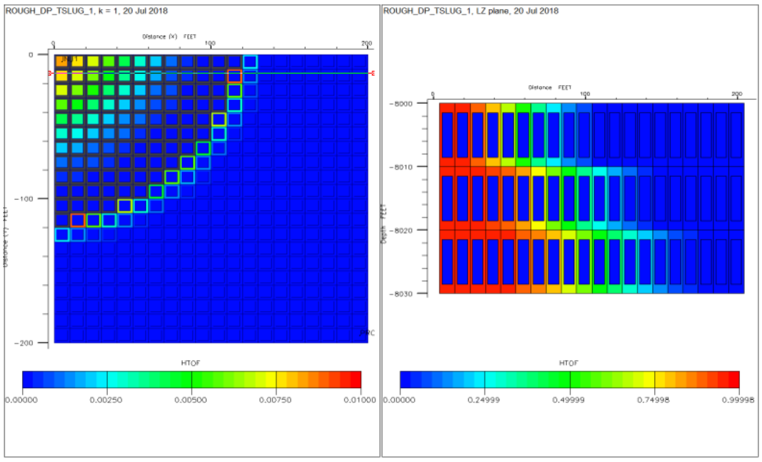

Figure 6.8: Cross-section plot of conservative tracer concentration after 1 day of injection.

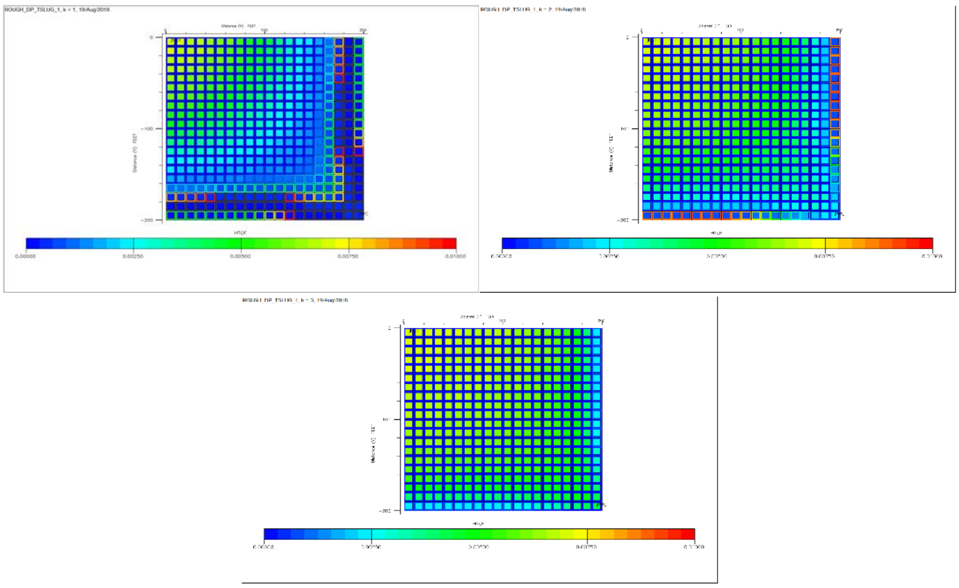

Figure 6.9: Conservative tracer concentration after 1 month of injection for the top layer (top left), middle (top right) and bottom layer (bottom).

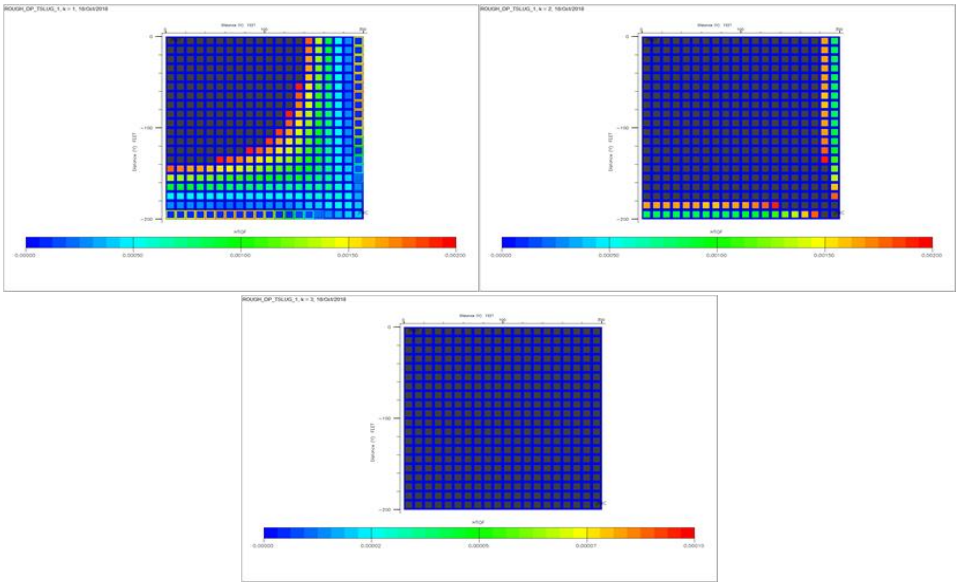

Figure 6.10: Conservative tracer concentration after 3 months of injection for the top layer (top left), middle (top right) and bottom layer (bottom).

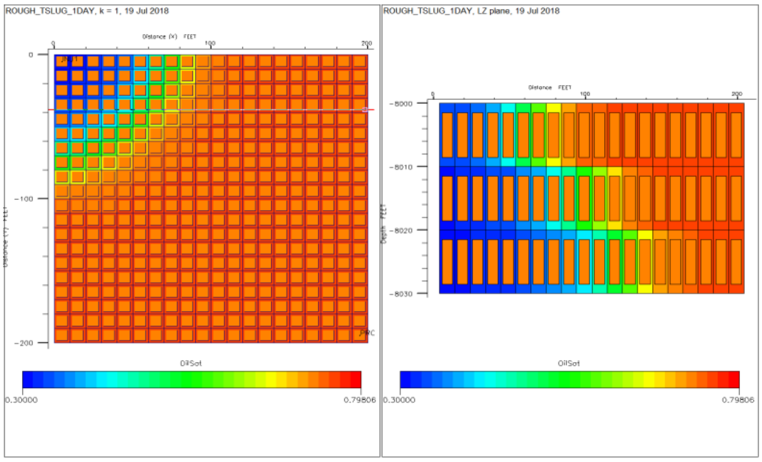

Figure 6.11: Cross-section plot of oil saturation after one day of injection in a dual permeability model.

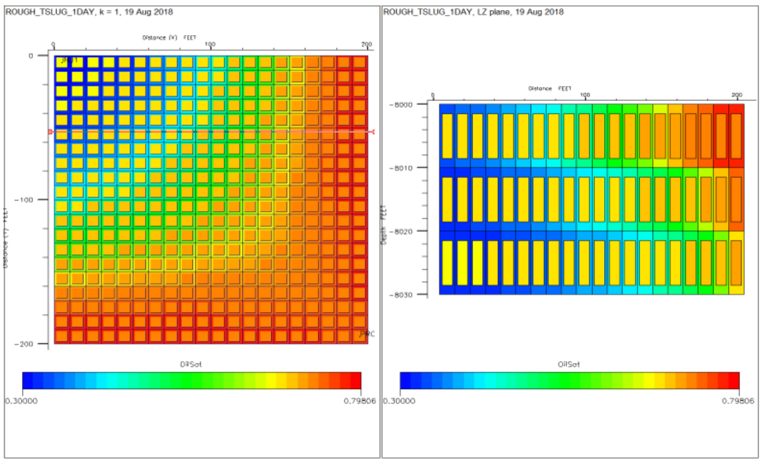

Figure 6.12: Cross-section plot of oil saturation after one month of injection in a dual permeability model.

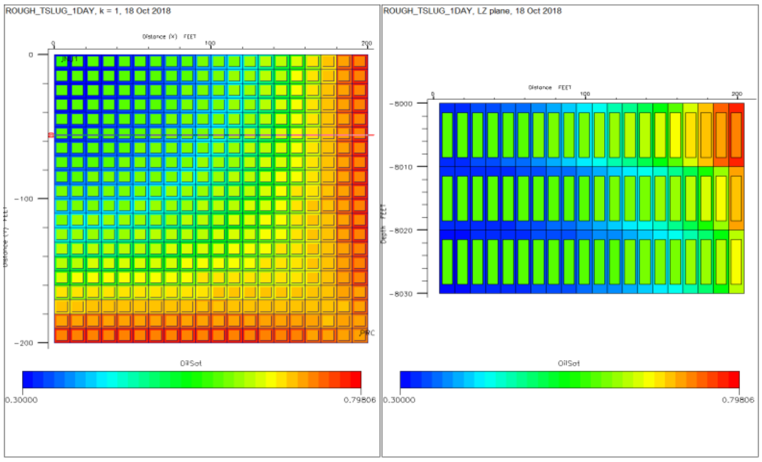

Figure 6.13: Cross-section plot of oil saturation after 3 months of injection in a dual permeability model.

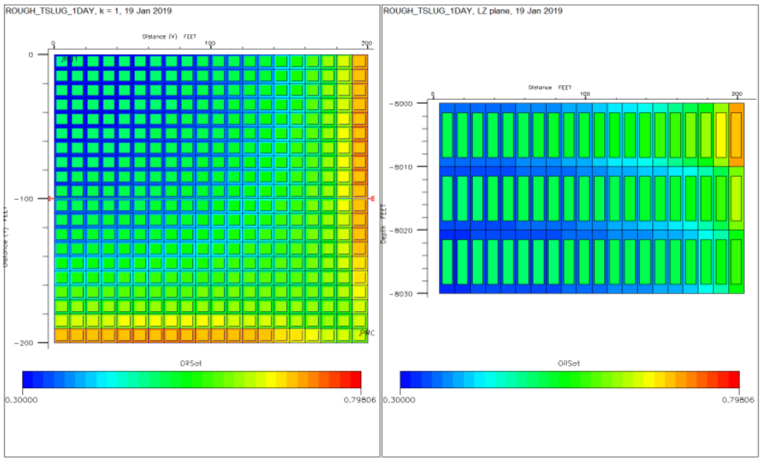

Figure 6.14: Cross-section plot of oil saturation after 6 months of injection in a dual permeability model.

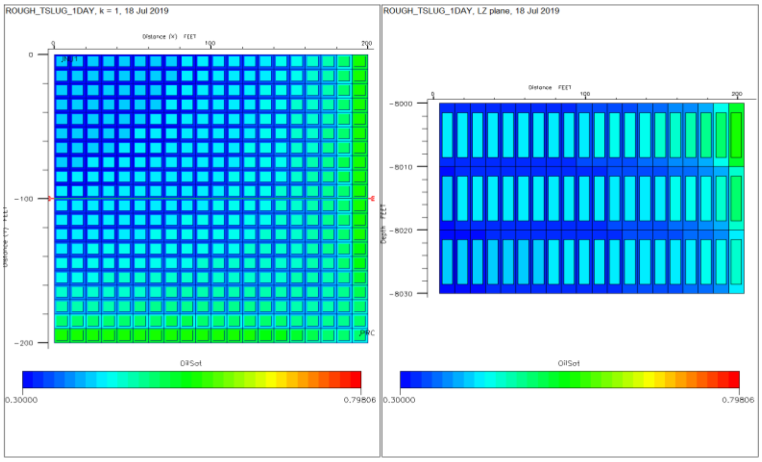

Figure 6.15: Cross-section plot of oil saturation after one year of injection in the dual permeability model.

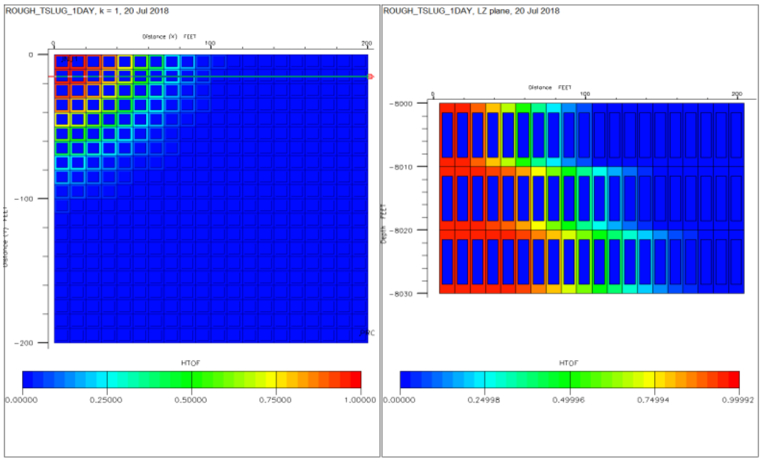

Figure 6.16: Cross-section plot of conservative tracer concentration after 1 day of injection, in the dual permeability model.

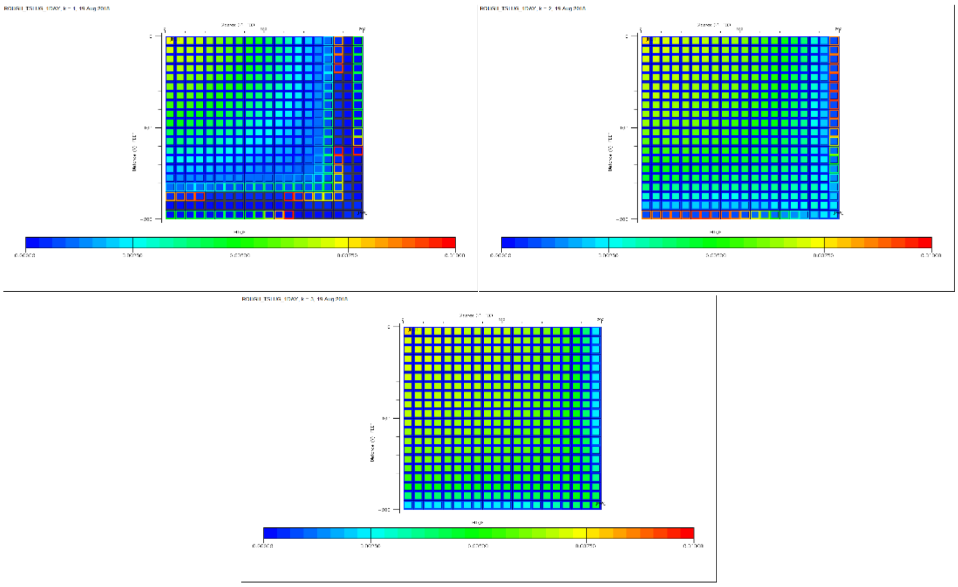

Figure 6.17: Conservative tracer concentration after 1 month of injection for the top layer (top left), middle (top right) and bottom layer (bottom), in the dual permeability model.

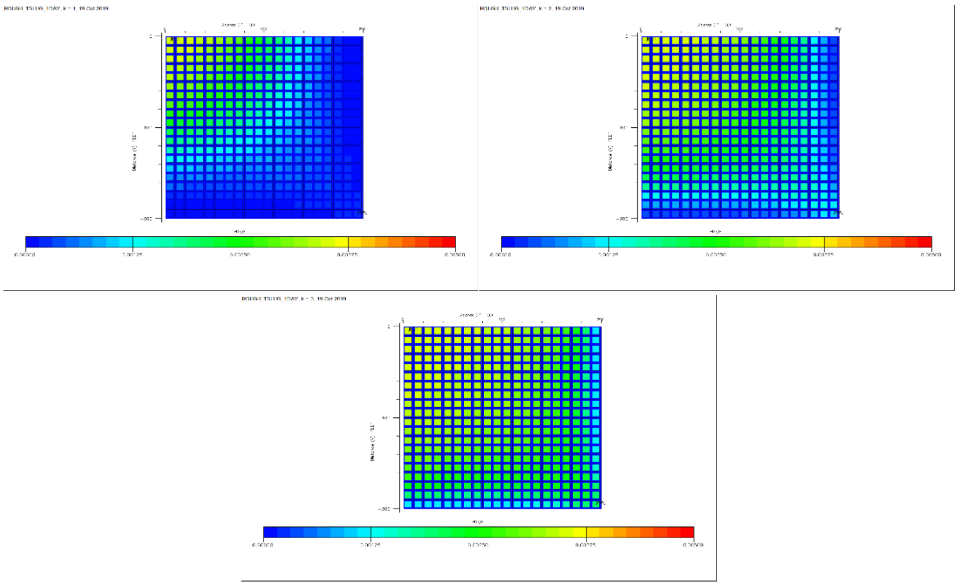

Figure 6.18: Conservative tracer concentration after 3 months of injection for the top layer (top left), middle (top right) and bottom layer (bottom), in the dual permeability model.

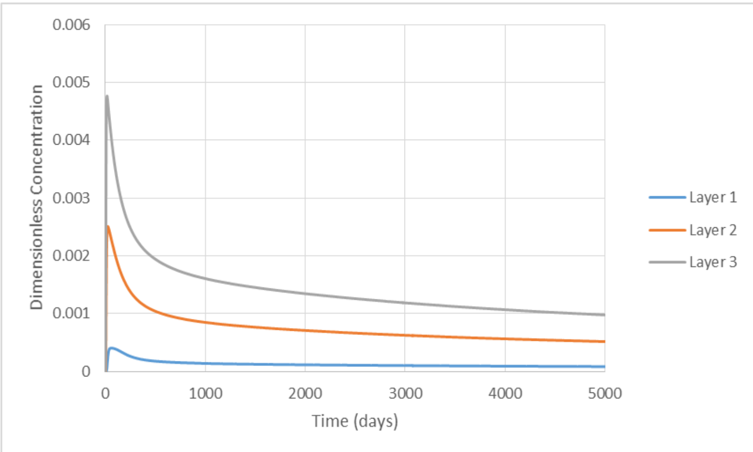

Figure 6.19: Conservative tracer response for each matrix connection in the dual permeability model.

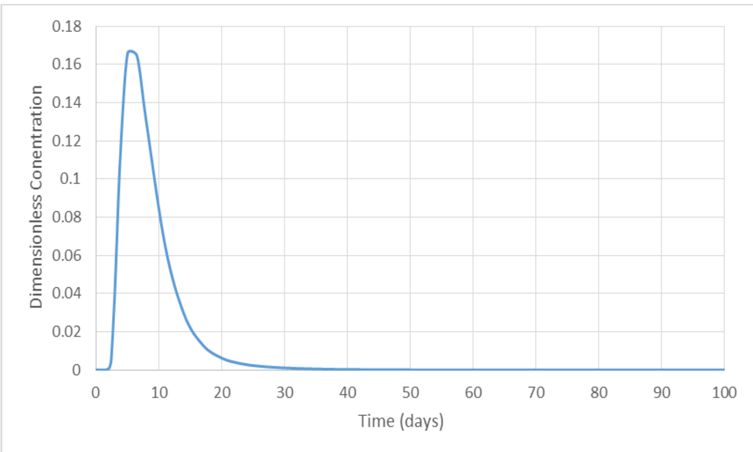

Figure 6.20: Conservative tracer average concentration response in the dual permeability model.

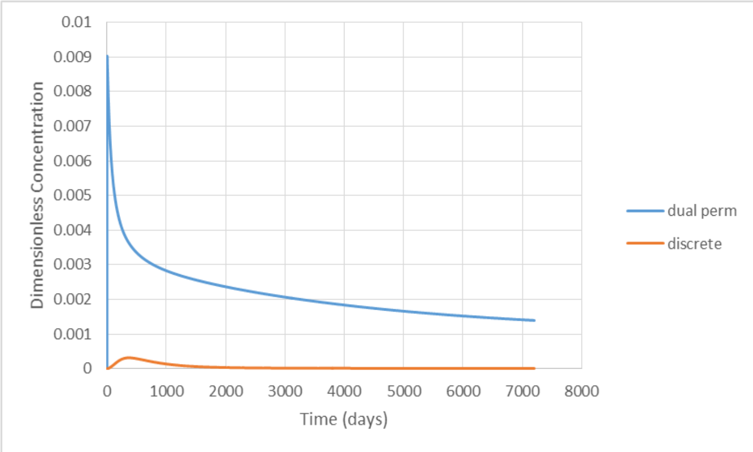

Figure 6.21: Conservative tracer response in a matrix block, for a dual permeability and a discrete fracture model.

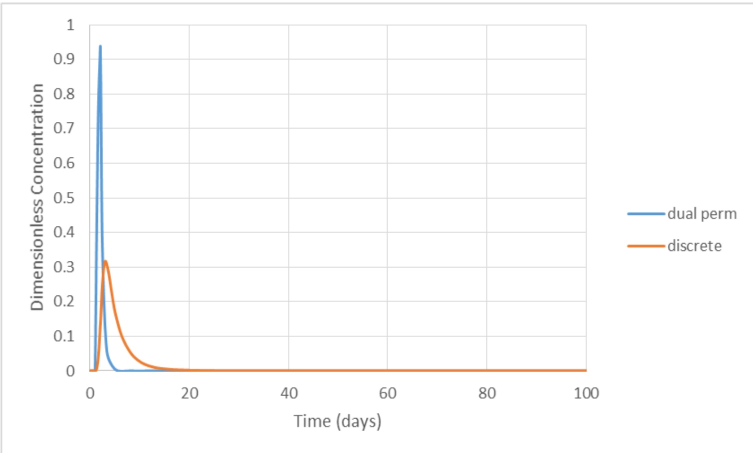

Figure 6.22: Conservative tracer average (field) response, for a dual permeability and a discrete fracture model.

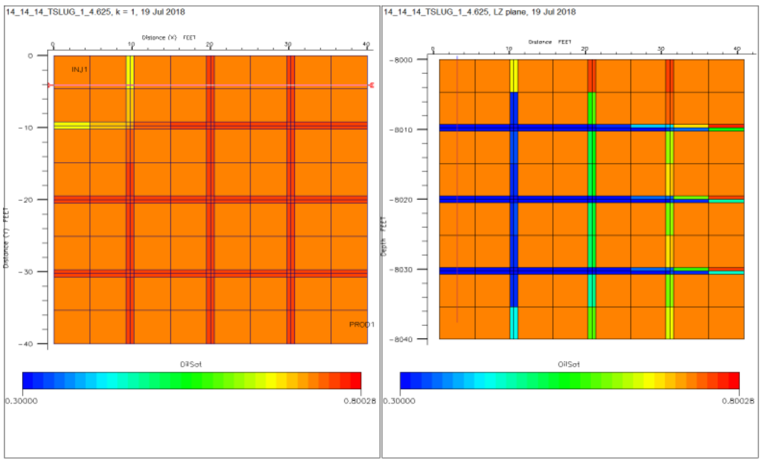

Figure 6.23: Cross section plot of oil saturation at day 1 in the discrete fracture model.

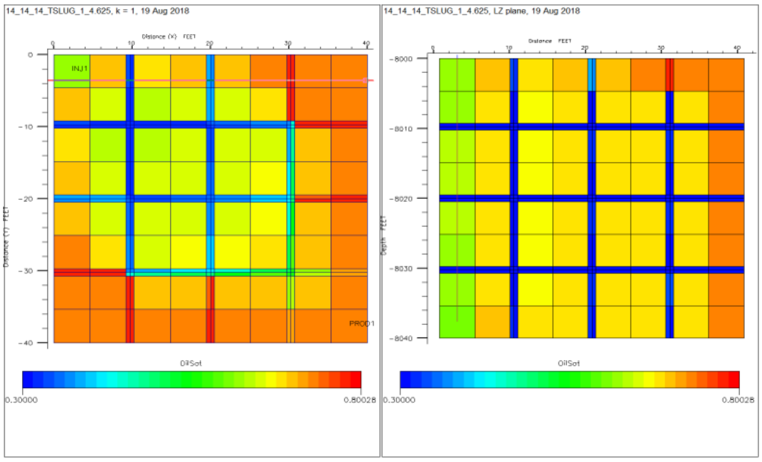

Figure 6.24: Cross section plot of oil saturation after 30 days of injection, in the discrete fracture model.

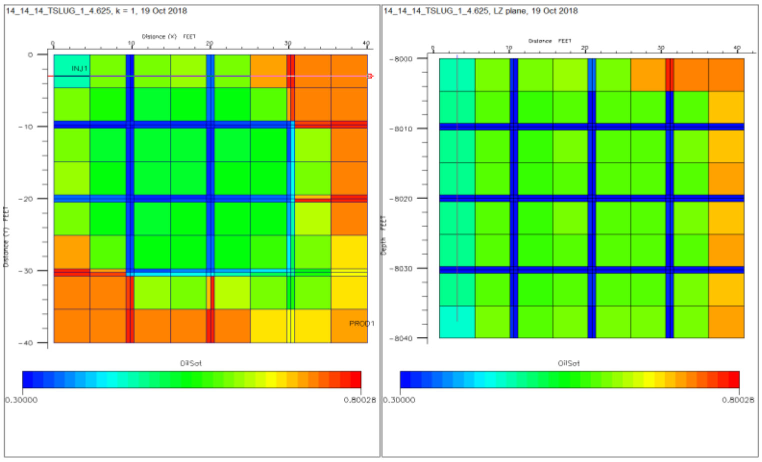

Figure 6.25: Cross section plot of oil saturation after 3 months of injection, in the discrete fracture model.

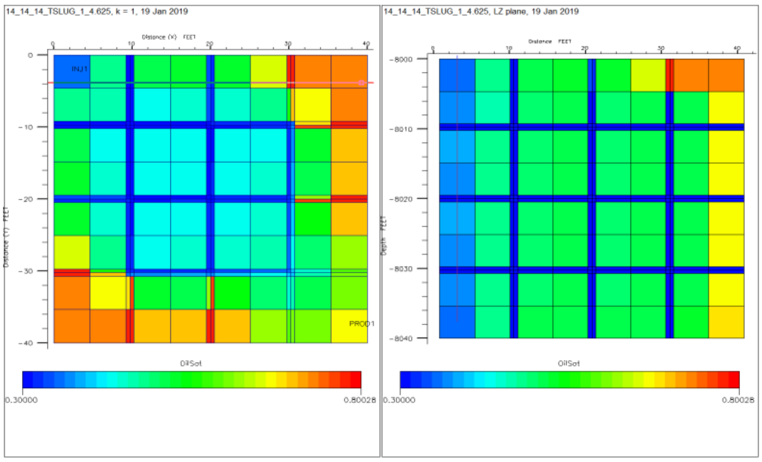

Figure 6.26: Cross section plot of oil saturation after 6 months of injection, in the discrete fracture model.

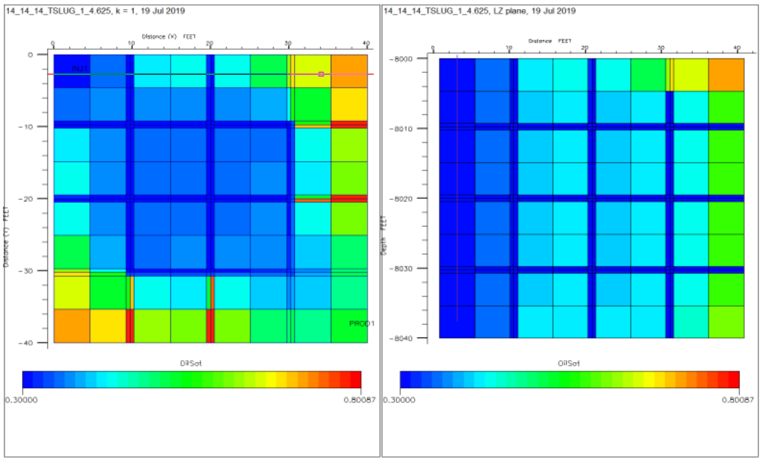

Figure 6.27: Cross section plot of oil saturation after one year of injection, in the discrete fracture model.

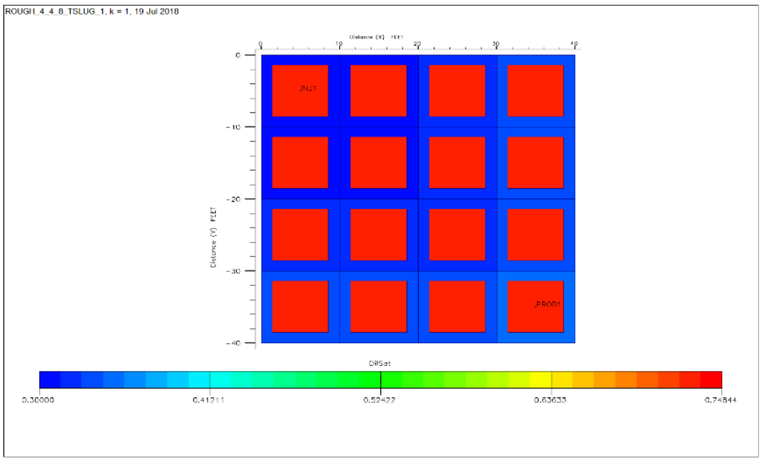

Figure 6.28: Oil saturation after 1 day of injection, in the dual permeability model.

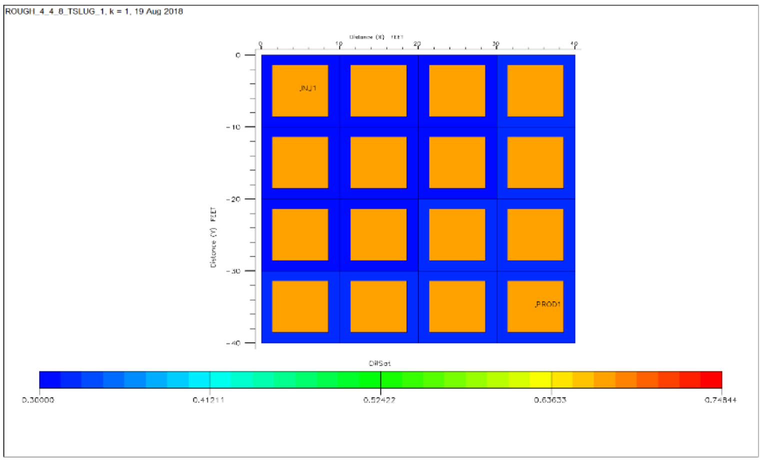

Figure 6.29: Oil saturation after 1 month of injection, in the dual permeability model.

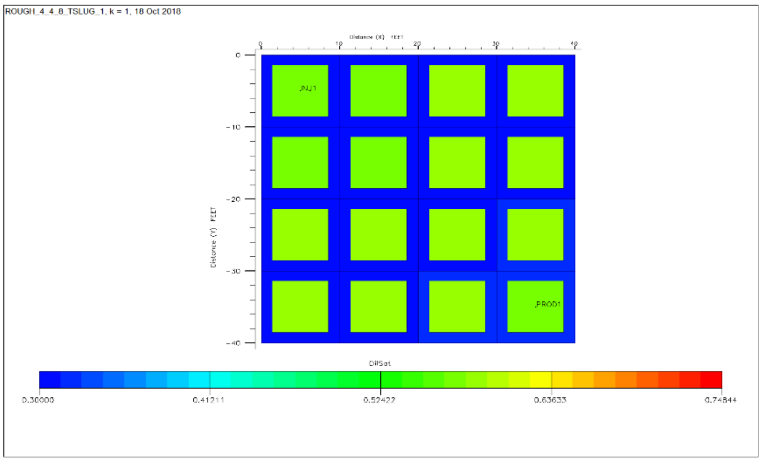

Figure 6.30: Oil saturation after 3 month of injection, in the dual permeability model.

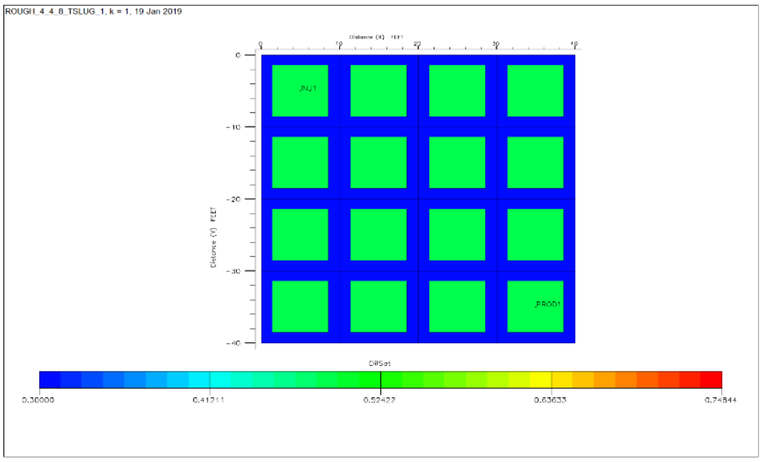

Figure 6.31: Oil saturation after 6 months of injection, in the dual permeability model.

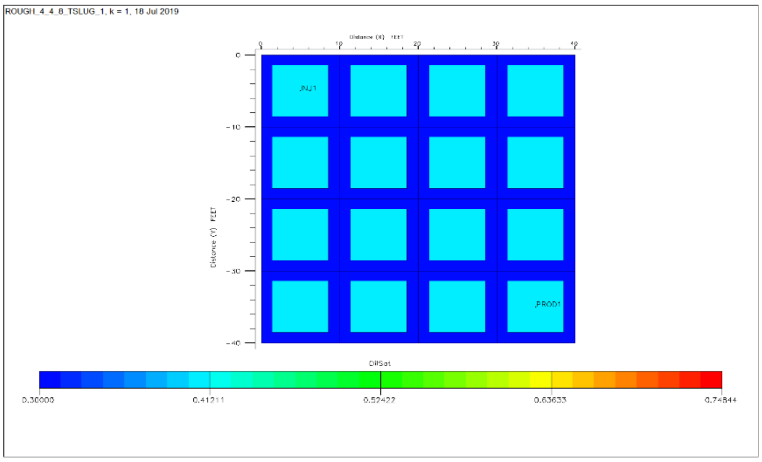

Figure 6.32: Oil saturation after 1 year of injection, in the dual permeability model.

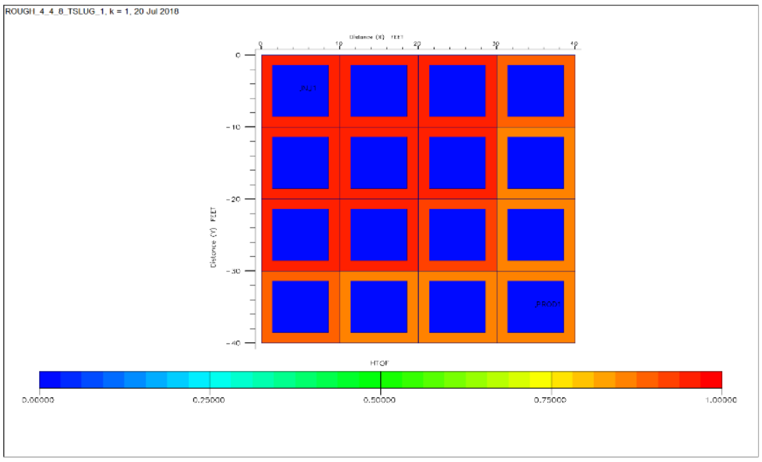

Figure 6.33: Conservative tracer concentration after 1 day of injection, in the dual permeability model.

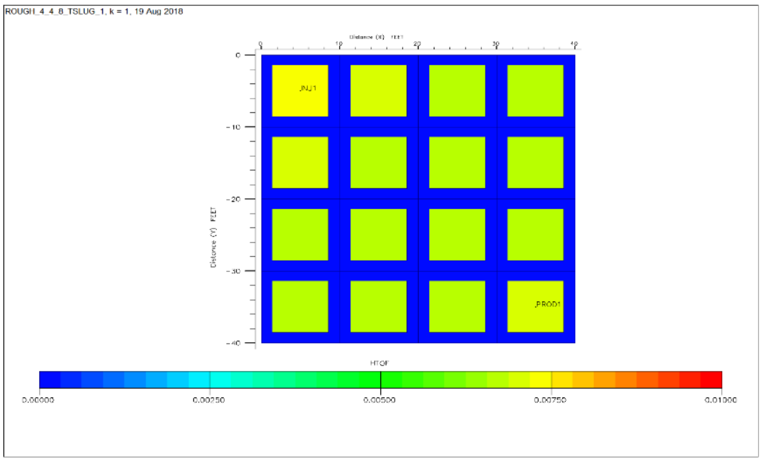

Figure 6.34: Conservative tracer concentration after 1 month of injection, in the dual permeability model.

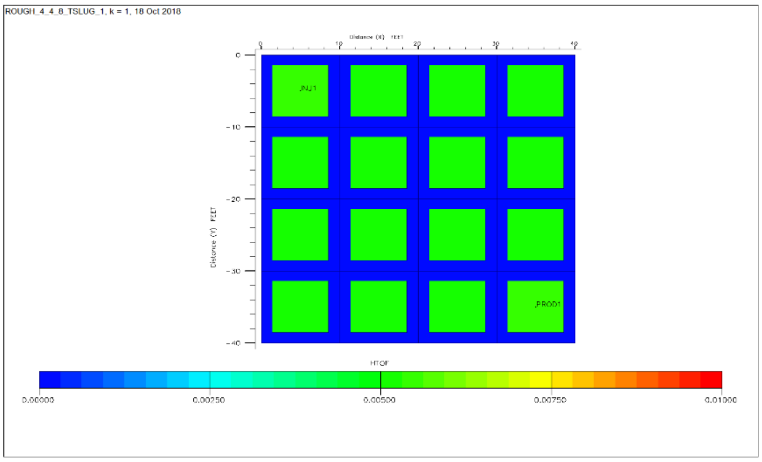

Figure 6.35: Conservative tracer concentration after 1 month of injection, in the dual permeability model.

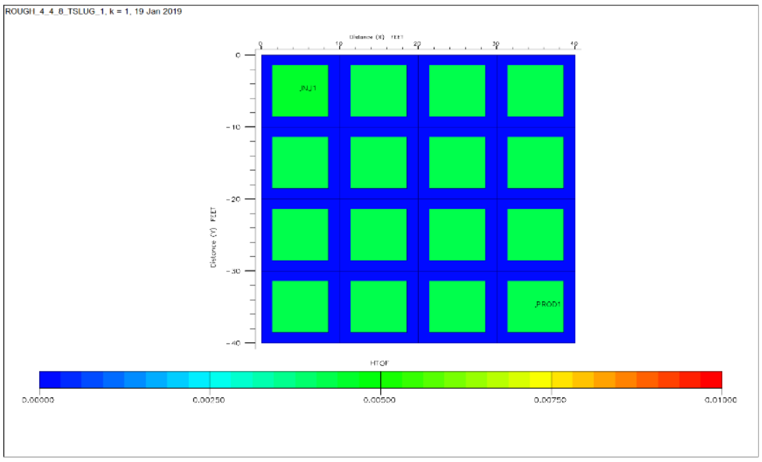

Figure 6.36: Conservative tracer concentration after 3 months of injection, in the dual permeability model.

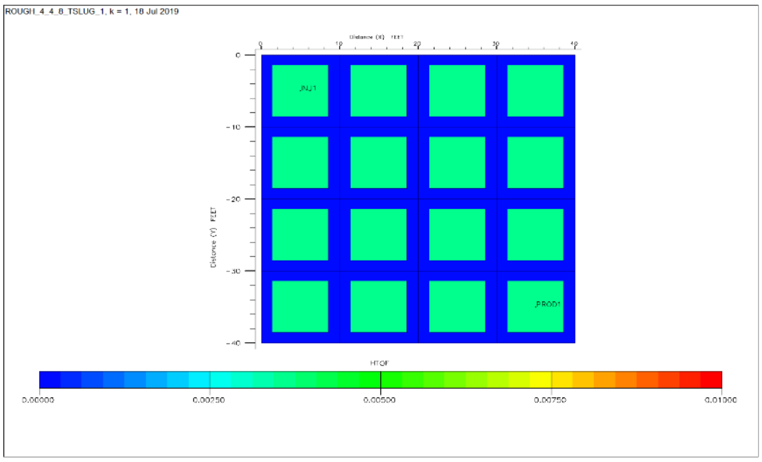

Figure 6.37: Conservative tracer concentration after one year of injection, in the dual permeability model.

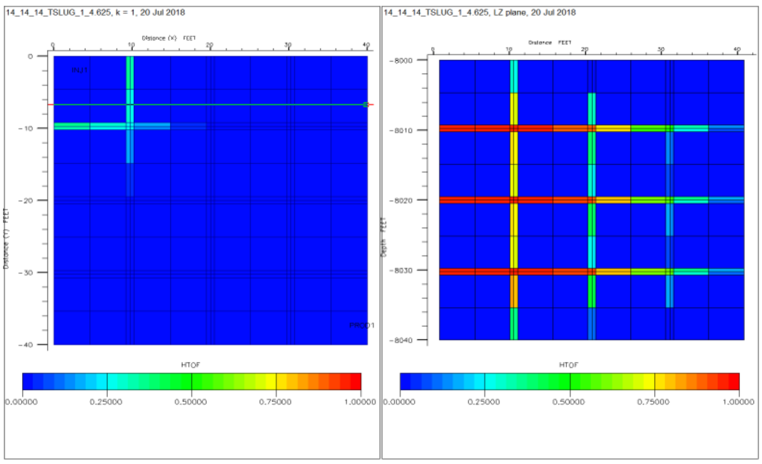

Figure 6.38: Conservative tracer concentration after one day of injection, in the dual permeability model.

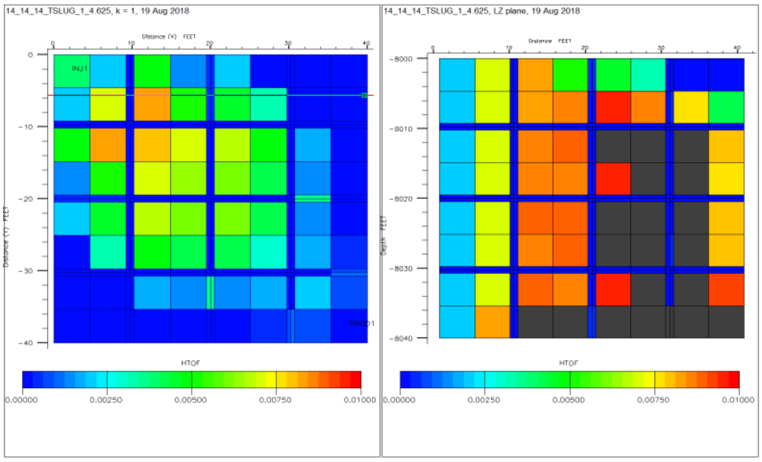

Figure 6.39: Conservative tracer concentration after one month of injection, in the dual permeability model.

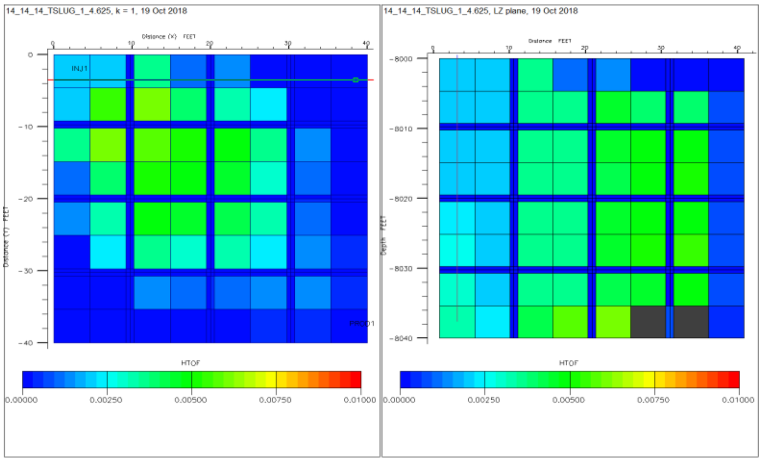

Figure 6.40: Conservative tracer concentration after 3 months of injection, in the dual permeability model.

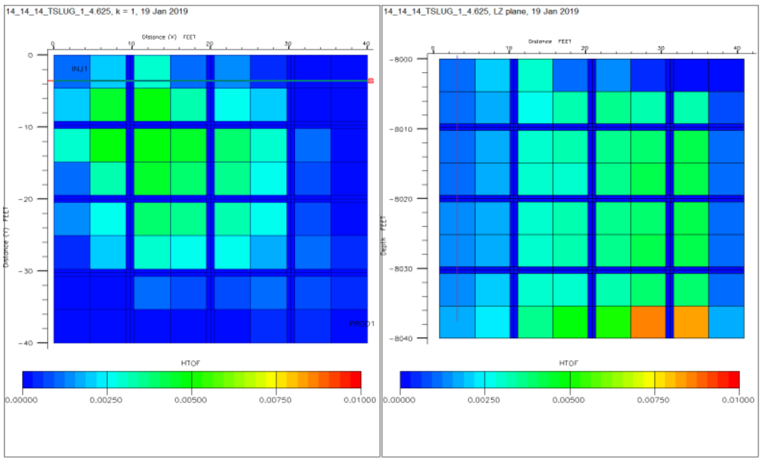

Figure 6.41: Conservative tracer concentration after 6 months of injection, in the dual permeability model.

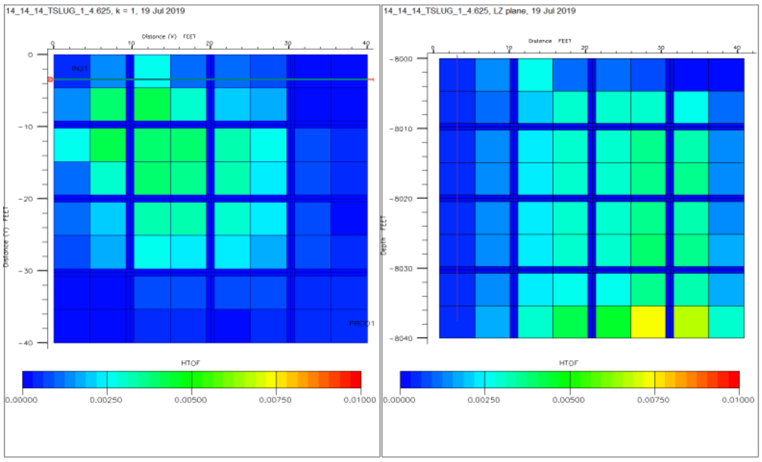

Figure 6.42: Conservative tracer concentration after 1 year, in the dual permeability model.

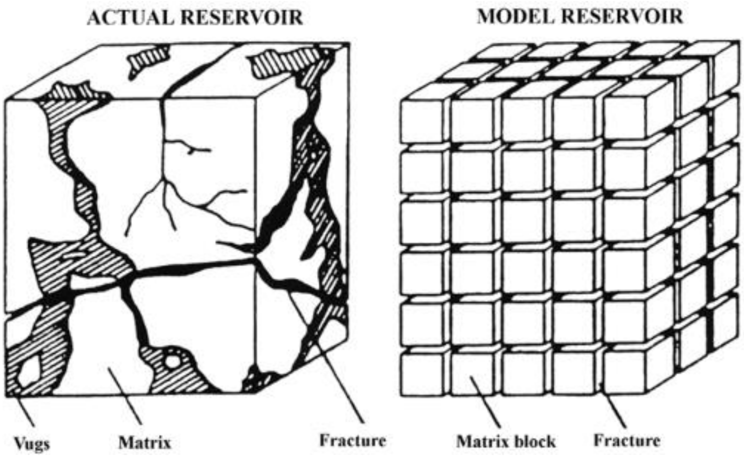

Figure 6.43: Graphic illustration of dual porosity model.

Tables of Chapter 6

Dual Porosity Model	
No. of blocks in x direction	20
No. of blocks in y direction	20
No. of blocks in z direction	6
D_x (per block)	10 ft.
D_y (per block)	10 ft.
D_z (per block)	10 ft.
Reservoir depth	8000 ft.
Matrix porosity (constant)	0.15
Fracture porosity (constant)	0.002
X permeability (fracture)	5000 mD
Y permeability (fracture)	5000 mD
X permeability (matrix)	0.5 mD
Y permeability (matrix)	0.5 mD
Z permeability (uniform)	0.05 mD
oil saturation (average)	0.75
Residual Oil Saturation (S_{or})	0.3
oil density	49 ppg
water density	63 ppg
Oil viscosity	1.74 cP (@Pres)
Water viscosity	1 cP
water compressiblity	3E-06 1/psi
rock compressibility	4E-06 1/psi
B_w	1.02
B_o @ Pres	1.17
reservoir pressure	4500 psi
Production rate	50 stb/day
Injection rate	50 stb/day
wellbore radius	4 inches

Table 6.1: Dual porosity case input.

Dual Permeability/Explicit	
No. of blocks in x direction	4
No. of blocks in y direction	4
No. of blocks in z direction	8
D_x (per block)	10 ft.
D_y (per block)	10 ft.
D_z (per block)	10 ft.
Reservoir depth	8000 ft.
Matrix porosity (constant)	0.15
Fracture porosity (constant)	0.002
X permeability (fracture)	5000 mD
Y permeability (fracture)	5000 mD
X permeability (matrix)	0.5 mD
Y permeability (matrix)	0.5 mD
Z permeability (uniform)	0.05 mD
oil saturation (average)	0.75
Residual Oil Saturation (S_{or})	0.3
oil density	49 ppg
water density	63 ppg
Oil viscosity	1.74 cP (@Pres)
Water viscosity	1 cP
water compressiblity	3E-06 1/psi
rock compressibility	4E-06 1/psi
B_w	1.02
B_o @ Pres	1.17
reservoir pressure	4500 psi
Production rate	50 stb/day
Injection rate	50 stb/day
wellbore radius	4 inches

Table 6.2: Dual permeability/ discrete fracture model case input.

7. Conclusions

By virtue of the higher order dispersion control being used in UTCHEM, the latter manages to provide more accurate results in terms of tracer transportation and propagation in comparison with ECLIPSE, at least for these study cases. Fully implicit models of 2nd (such as the ones being utilised in ECLIPSE) or lower order accuracy are highly susceptible to numerical dispersion. This can be realised by deriving and utilising an analytical solution for a 1D grid. Similarly, in terms of a 2D grid description, predictions obtained from numerical techniques are slightly more precise if UTCHEM is used as a simulator.

With regards to numerical methods, if the saturation exhibits a residual value, predictions tend to be fairly accurate. Mean Residence Time is the most rigid technique and the generated results are approximately the same regardless of the saturation distribution. On the other hand, mode time, breakthrough time and $t_{50\%}$ are sensitive to saturation distributions, and the obtained predictions vary according to those distributions. Mathematically this can be explained from the very values that these numerical methods use as inputs. Mode time, breakthrough time and $t_{50\%}$ utilise two distinct points (a discrete time value regarding conservative and partitioning tracer), whilst Mean Residence Time requires area calculations. Hence, the former are prone to exhibit variations if a different saturation distribution is used.

Apart from Mean Residence Time estimations, all other techniques heavily depend upon the saturation distribution. If higher oil saturations occur across the main (diagonal) flow path the prediction concerning residual oil saturation will be over-optimistic and vice versa. Large variations of oil saturation distribution increase non-linearity and locally two-phase flow may be conducted from the simulator. Convergence may be facilitated if proper averaging is performed in terms of saturation distribution.

For all methods it can be inferred as a rule of thumb that, the higher the residual saturation the better the prediction and vice versa.

The usage of breakthrough time depends on physical dispersion in a real experiment, and on numerical dispersion in a simulation run. The original breakthrough time of a tracer, should dispersion (both mechanical and numerical) is eliminated, is in reality mode time.

Numerical methods may yield descent predictions in terms of mobile oil cases. The closer this value is to residual saturation the better the prediction. If the wettability of the system is friendly to oil then predictions are even more precise. With respect to production stage, tracer testing is applied chiefly before EOR application, in which the remaining oil saturation is probably at its irreducible saturation or slightly higher than that due to production. Thus, at this very stage, predictions are fairly accurate.

Regarding heterogeneous reservoirs, tracers may give valuable insight in terms of flow patterns and phenomena such as crossflow. By utilising production data alongside tracers such phenomena can be well-determined. In the petroleum industry PITT is a primary tool for realising heterogeneities.

PITT gives useful information in the case of naturally fractured reservoirs as well. The slow process of water penetration and displacement of oil can be realised from tracer responses. On the other hand, numerical techniques implementation is pointless due to quick dispersive response within the fracture system and the slow diffusive response within the matrix.

The selection between a dual porosity or dual permeability model and an explicit fracture one should be made for each particular case. In general, in the default dual porosity model matrix-fracture transmissibility exhibits higher value than the discrete fracture model, for given reservoir properties. The use of transmissibility multipliers may render both models comparable.

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APPENDICES

Appendix A

0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8
0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Water saturation Distribution 1 in the neutral wet system (average S_{or}= 0.35).

0.5	0.5	0.5	0.5	0.5	1	1	1	1	1
0.5	0.5	0.5	0.5	0.5	0.5	1	1	1	1
0.5	0.5	0.5	0.5	0.5	0.5	0.5	1	1	1
0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1	1
0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1
1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	1	1	0.5	0.5	0.5	0.5	0.5	0.5	0.5
1	1	1	1	0.5	0.5	0.5	0.5	0.5	0.5
1	1	1	1	1	0.5	0.5	0.5	0.5	0.5

Water saturation Distribution 2 in the neutral wet system (average S_{or}= 0.35).

0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.5	0.6
0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
0.6	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8
0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8
0.8	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.8
0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.7

Water saturation Distribution 3 in the neutral wet system (average S_{or}= 0.35).

0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9
0.4	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9
0.5	0.4	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9
0.6	0.5	0.4	0.4	0.4	0.5	0.6	0.7	0.7	0.8
0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6	0.7	0.8
0.8	0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6	0.7
0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6
0.8	0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4	0.5
0.9	0.8	0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4
0.9	0.9	0.8	0.7	0.7	0.7	0.6	0.5	0.4	0.4

Water saturation Distribution 4 in the neutral wet system (average S_{or}= 0.35).

0.9	1	1	1	0.9	0.9	0.9	0.9	0.9	0.8
0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7
0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0
0.7	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
0.7	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
0.7	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
0.7	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7
0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7
0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Water saturation Distribution 1 in the oil wet system (average S_{or}= 0.4).

0.4	0.4	0.4	0.4	1	1	1	1	1	1
0.4	0.4	0.4	0.4	0.4	0.6	0.6	1	1	1
0.4	0.4	0.4	0.4	0.4	0.4	1	1	1	1
0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	1	1
0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	1
1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
1	1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
1	1	1	0.4	0.4	0.4	0.4	0.4	0.4	0.4
1	1	1	1	0.6	0.4	0.4	0.4	0.4	0.4
1	1	1	1	1	1	0.6	0.4	0.4	0.4

Water saturation Distribution 2 in the oil wet system (average S_{or}= 0.4).

0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.5	0.6
0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
0.6	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8
0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8
0.8	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.8
0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.7

Water saturation Distribution 3 in the oil wet system (average S_{or}= 0.4).

0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9
0.4	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9
0.5	0.4	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9
0.6	0.5	0.4	0.4	0.4	0.5	0.6	0.7	0.7	0.8
0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6	0.7	0.8
0.8	0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6	0.7
0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4	0.5	0.6
0.8	0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4	0.5
0.9	0.8	0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4
0.9	0.9	0.8	0.7	0.7	0.7	0.6	0.5	0.4	0.4

Water saturation Distribution 4 in the oil wet system (average S_{or}= 0.4).

0.9	1	1	1	0.9	0.9	0.9	0.9	0.9	0.8
0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.6	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.5	0.6
0.7	0.5	0.4	0.3	0.3	0.3	0.3	0.4	0.5	0.7
0.7	0.5	0.4	0.3	0.3	0.3	0.3	0.4	0.5	0.7
0.7	0.5	0.4	0.3	0.3	0.3	0.3	0.4	0.5	0.7
0.7	0.5	0.4	0.4	0.3	0.4	0.4	0.4	0.5	0.6
0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Water saturation Distribution 1 in the strongly oil wet system (average S_{or}= 0.4).

0.3	0.4	0.4	0.5	1	1	1	1	1	1
0.4	0.3	0.4	0.4	0.5	0.4	0.5	1	1	1
0.4	0.4	0.3	0.4	0.4	0.5	1	1	1	1
0.5	0.4	0.4	0.3	0.4	0.4	0.5	0.5	1	1
0.4	0.5	0.4	0.4	0.3	0.4	0.4	0.5	0.5	1
1	0.4	0.5	0.4	0.4	0.3	0.4	0.4	0.5	0.5
1	1	0.4	0.5	0.4	0.4	0.3	0.4	0.4	0.5
1	1	1	0.4	0.4	0.4	0.4	0.3	0.4	0.4
1	1	1	1	0.5	0.5	0.4	0.4	0.3	0.4
1	1	1	1	1	1	0.5	0.4	0.4	0.3

Water saturation Distribution 2 in the strongly oil wet system (average S_{or}= 0.4).

0.8	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7
0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.6	0.7
0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
0.5	0.4	0.4	0.3	0.3	0.4	0.4	0.5	0.5	0.6
0.5	0.4	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6
0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
0.6	0.5	0.5	0.6	0.5	0.4	0.3	0.4	0.5	0.6
0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
0.8	0.8	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.8
0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.7	0.7	0.7

Water saturation Distribution 3 in the strongly oil wet system (average S_{or}= 0.4).

0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.9	0.9	1
0.4	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.9	1
0.5	0.4	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.9
0.6	0.5	0.4	0.3	0.4	0.5	0.6	0.7	0.8	0.8
0.7	0.6	0.5	0.4	0.3	0.4	0.5	0.6	0.7	0.8
0.8	0.7	0.6	0.5	0.4	0.3	0.4	0.5	0.6	0.7
0.8	0.8	0.7	0.6	0.5	0.4	0.3	0.4	0.5	0.6
0.8	0.8	0.8	0.7	0.6	0.5	0.4	0.3	0.4	0.5
0.9	0.8	0.8	0.8	0.7	0.6	0.5	0.4	0.3	0.4
1	0.9	0.8	0.7	0.7	0.7	0.6	0.5	0.4	0.3

Water saturation Distribution 4 in the strongly oil wet system (average S_{or}= 0.4).

0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5
0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.5
0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.5
0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.5
0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.5
0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.5
0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.5
0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7

Water saturation Distribution 1 in the strongly oil wet system (average S_{or}= 0.5).

0.3	0.3	0.3	0.5	0.7	0.8	0.8	0.8	0.8	0.8
0.3	0.3	0.3	0.4	0.4	0.7	0.8	0.8	0.8	0.8
0.3	0.3	0.3	0.3	0.4	0.4	0.7	0.7	0.8	0.8
0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.7	0.8
0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.8
0.8	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4
0.8	0.7	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4
0.8	0.8	0.7	0.4	0.4	0.3	0.3	0.3	0.3	0.4
0.8	0.8	0.7	0.7	0.7	0.4	0.4	0.3	0.3	0.3
0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.4	0.3	0.3

Water saturation Distribution 2 in the strongly oil wet system (average S_{or}= 0.5).

0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
0.5	0.4	0.4	0.3	0.3	0.3	0.4	0.4	0.5	0.6
0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4
0.5	0.4	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6
0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
0.6	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.4
0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7
0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6

Water saturation Distribution 3 in the strongly oil wet system (average S_{or}= 0.5).

0.3	0.3	0.4	0.5	0.6	0.7	0.7	0.7	0.7	0.7
0.3	0.3	0.3	0.4	0.5	0.6	0.6	0.7	0.7	0.7
0.4	0.3	0.3	0.3	0.4	0.5	0.6	0.7	0.7	0.7
0.5	0.4	0.3	0.3	0.3	0.4	0.5	0.6	0.7	0.7
0.6	0.5	0.4	0.3	0.3	0.3	0.4	0.5	0.6	0.7
0.7	0.6	0.5	0.4	0.3	0.3	0.3	0.4	0.5	0.6
0.7	0.7	0.6	0.5	0.4	0.3	0.3	0.3	0.4	0.5
0.7	0.7	0.7	0.6	0.5	0.4	0.3	0.3	0.3	0.4
0.7	0.7	0.7	0.7	0.6	0.5	0.4	0.3	0.3	0.3
0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.4	0.3	0.3

Water saturation Distribution 4 in the strongly oil wet system (average S_{or}= 0.5).

Appendix B

-- 1D MODEL (ECLIPSE)

```
RUNSPEC

TITLE
-- Tracers' Injection Model 100*100*30 ft^3 reservoir

DIMENS
200 1 1 /
-- cubic block of 0.5*100*30 ft^3
OIL
WATER

FIELD

TRACERS
-- info in terms of passive tracers being used
1* 2 2* DIFF 20 /

START
18 JUL 2018 /
WELLDIMS
2 8 2 1 /

UNIFOUT

PARTTRAC
-- Max no of partitioned tracers, No of K(p) tables in TRACERKP, Max no of pres points in K(p)
in TRACERKP
1 1 2 /

GRID

DX
200*0.5 /

DY
200*100 /

DZ
200*30 /

BOX
1 200 1 1 1 1 /

TOPS
200*8000 /
-- Depth of top blocks arbitrarily taken at 8000 ft.
ENDBOX

BOX
1 200 1 1 1 1 /
PORO
200*0.25 /
ENDBOX

BOX
1 200 1 1 1 1 /
PERMX
200*1000 /
ENDBOX

BOX
1 200 1 1 1 1 /
PERMY
200*1000 /
ENDBOX

BOX
1 200 1 1 1 1 /
PERMZ
200*100 /
```

```
ENDBOX

INIT

EDIT

PROPS

TRACER
-- tracer name, WAT, 'STB', Sol Phase, No of K(P) table,
HTO WAT /
PRT WAT 1* OIL 1 /
/

TRACERKP
-- P (increasing), Partition Coefficient
14.7 1
4500 1
/

TRACITVD
--(for implicit tracer calculation) TRACTVD (for explicit one)
/

PVDO
-- P Bo ì
300 1.25 1.0
800 1.20 1.1
6000 1.15 2.0 /

DENSITY
-- ño(s.c) ñw(s.c) ñg(s.c)
49 63 0.01 /

PVTW
-- Pref Bw Cw ìW viscosibility(usually 0)
4500 1.02 3.0E-06 0.8 0.0 /

ROCK
-- Pref C
4500 4E-06 /

SWOF
-- Sw Krw Kro Pcwo
0.1 0.0 1 4
0.3 0.4 0.4 0.8
0.5 1 0 0 /

SOLUTION

PRESSURE
200*4500 /

DATUM
8030 /

TVDPFHTO
8000 0.0
8030 0.0 /

TVDPFPRT
8000 0.0
8030 0.0 /

SWAT
200*0.75 /

RPTSOL
RESTART=2 FIP FIPTR=2 /

RPTRST
BASIC=2 NORST=1 /


SUMMARY
FPR
WBHP
```

```
/
FOPR
FWPR
FOPT
FWPT
FWCT
FOE
FTPRHTO
FTPRPRT
-- tracer prod rate

FTPTHTO
FTPTPRT
-- tracer total production

FTIRHTO
FTIRPRT
-- tracer inj rate

FTITHTO
FTITPRT
-- tracer total injection

FTPCHTO
FTPCPRT
-- tracer prod concentration

FTICHTO
FTICPRT
-- tracer inj concentration

FTIPTHTO
FTIPTPRT
-- tracer in place (total)

FTIPFHTO
FTIPFPRT
-- tracer in place (free)

FTIPSPRT
-- tracer in place (solution)

FTIRFHTO
FTIRFPRT
FTIRSPRT
-- tracer inj rate (free and solution)

FTPRFHTO
FTPRFPRT
FTPRSPRT
-- tracer prod rate (free & solution)

FTICFHTO
FTICFPRT
FTICSPRT
-- tracer inj concertation (free

FTPCFHTO
FTPCFPRT
FTPCSPRT
-- tracer prod concertation (free & solution)

--BOSAT
-- oil saturation

FOSAT
-- average oil saturation
FWSAT
FWIR
FWPR
FWIPR
FWIPT

BVELWI
1 1 1 /
5 1 1 /
10 1 1 /
```

```
30 1 1 /
50 1 1 /
80 1 1 /
100 1 1 /
130 1 1 /
150 1 1 /
170 1 1 /
200 1 1 /
/

TCPU
EXCEL

SCHEDULE

RPTSCHED
RESTART=2 SUMMARY=2 FIPTR=1 TRACER /

RPTRST
BASIC=2 NORST=1 /

WELSPECS
PROD1 G1 1 1 8015 OIL /
INJ1 G2 200 1 8015 WATER /
/

COMPDAT
PROD1 1 1 1 1 OPEN 2* 0.3333 /
INJ1 200 1 1 1 OPEN 2* 0.3333 /
-- 8 in production tubing
 /

WCONPROD
'PROD1' OPEN LRAT 3* 50 1* 3500 /
-- 7000 STB/D LIQUID RATE
-- 9th item is lowermost BHP, which is the hydrostatic (ñ=63)
/

WCONINJE
 'INJ1' WATER OPEN RATE 50 /
/

TIME
1 /

WTRACER
-- * * Tracer_Concentration_in_inj_well
INJ1 HTO 1 /
INJ1 PRT 1 /
/

TIME
2 /

WTRACER
-- * * Tracer_Concentration_in_inj_well
INJ1 HTO 0 /
INJ1 PRT 0 /
/


TSTEP
0.0001 0.0001 0.0003 0.0005 0.0007 0.0009 0.001 0.003 0.005 0.007 0.009 0.01 0.03 0.05 0.07
0.09 0.1 0.3 0.5 0.7 0.9 979*1 /

END
```

-- Random Distribution (ECLIPSE)

```
RUNSPEC

TITLE
-- Tracers' Injection Model 1000*1000*90 ft^3 reservoir

DIMENS
100 20 1 /
OIL
WATER

NSTACK
200 /

NUPCOL
5 /

FIELD

TRACERS
1* 5 2* DIFF 30 /

START
18 JUL 2018 /
WELLDIMS
2 3 2 1 /

UNIFOUT

PARTTRAC
-- Max no of partitioned tracers, No of K(p) tables in TRACERKP, Max no of pres points in K(p)
in TRACERKP
4 4 2 /

ENDSCALE
DIRECT IRREVERS /

GRID

DX
2000*10 /

DY
2000*50 /

DZ
2000*90 /

BOX
1 100 1 20 1 1 /

TOPS
2000*8000 /
ENDBOX

BOX
1 100 1 20 1 1 /
PORO
2000*0.25 /
ENDBOX

BOX
1 100 1 20 1 1 /
PERMX
2000*1000 /
ENDBOX

BOX
1 100 1 20 1 1 /
PERMY
2000*1000 /
ENDBOX

BOX
1 100 1 20 1 1 /
```

```
PERMZ
2000*100 /
ENDBOX

INIT

EDIT

PROPS

TRACER
-- tracer name, WAT, 'STB', Sol Phase, No of K(P) table,
HTO WAT /
PR1 WAT 1* OIL 1 /
PR2 WAT 1* OIL 2 /
PR3 WAT 1* OIL 3 /
PR4 WAT 1* OIL 4 /
/

TRACERKP
-- P (increasing), Partition Coefficient
14.7 0.5
4500 0.5
/
14.7 1
4500 1
/
14.7 1.5
4500 1.5
/
14.7 2
4500 2
/

PVDO
-- P Bo ì
300 1.25 1.0
800 1.20 1.1
6000 1.15 2.0 /

DENSITY
-- ño(s.c) ñw(s.c) ñg(s.c)
49 63 0.01 /

PVTW
-- Pref Bw Cw ìW viscosibility
4500 1.02 3.0E-06 0.8 0.0 /

ROCK
-- Pref C
4500 4E-06 /

SWOF
-- Sw Krw Kro Pcwo
0.1 0.0 1 4
0.2 0.3333 0.6666 0.8
0.3 0.6666 0.3333 0.2
0.4 1 0 0
0.5 1 0 0 /

REGIONS

TRKPFPR1
2000*1 /
TRKPFPR2
2000*2 /
TRKPFPR3
2000*3 /
TRKPFPR4
2000*4 /

SOLUTION

PRESSURE
2000*4500 /

DATUM
```

```
8090 /

TVDPFHTO
8000 0.0
8090 0.0 /

TVDPFPR1
8000 0.0
8090 0.0 /

TVDPFPR2
8000 0.0
8090 0.0 /

TVDPFPR3
8000 0.0
8090 0.0 /

TVDPFPR4
8000 0.0
8090 0.0 /

SWAT
0.81    0.5     0.85    0.92    0.92    0.63    0.53    0.97    0.72    0.76    0.5     0.52    1
        0.73    0.6     0.97    0.71    0.8     1       0.74
0.63    0.78    0.53    0.54    0.63    0.62    0.83    0.52    0.79    0.52    0.93    0.86    0.76
        0.95    0.93    0.94    0.86    0.95    0.6     0.69
0.93    0.96    0.9     0.82    0.82    0.65    0.93    0.98    0.61    1       0.94    0.77    0.81
        0.87    0.88    0.6     0.79    0.58    0.9     0.92
0.95    0.7     0.69    0.82    0.78    0.72    0.71    0.82    0.95    0.87    0.55    0.88    0.78
        0.99    0.62    0.88    0.98    0.73    0.57    0.88
0.65    0.87    0.62    0.8     1       0.5     0.54    0.53    0.99    0.7     0.66    0.74    0.7
        0.8     0.5     0.52    0.99    0.98    0.78    0.66
0.66    0.99    0.8     0.96    0.53    0.7     0.92    0.66    0.9     0.52    0.86    0.51    0.94
        0.96    0.92    0.5     0.91    0.93    0.54    0.52
0.77    0.96    0.63    0.57    0.92    1       0.67    0.77    1       0.91    0.69    0.54    0.51
        0.83    0.63    0.54    0.82    0.76    0.88    0.79
0.87    0.6     0.72    0.79    0.69    0.78    0.96    0.66    0.51    0.52    0.91    0.56    0.74
        1       0.57    0.52    0.95    0.68    0.9     0.71
0.61    0.58    0.57    0.71    0.6     0.86    0.94    0.88    0.85    0.59    0.53    0.71    0.66
        0.66    0.88    0.69    0.92    0.81    0.98    0.81
0.97    0.9     0.66    0.67    0.72    0.57    0.94    0.69    0.97    0.65    0.59    0.58    0.87
        0.66    0.76    0.76    0.69    0.61    0.61    0.57
0.58    0.58    0.54    0.7     0.8     0.62    0.61    0.71    0.52    0.76    0.72    0.86    1
        0.56    0.78    0.86    0.79    0.99    0.81    0.71
0.79    0.6     0.57    0.98    0.8     0.62    0.85    0.57    0.51    0.73    0.85    0.78    0.85
        0.85    0.71    0.82    0.81    0.99    0.54    0.79
0.71    0.95    0.76    1       0.9     0.59    0.76    0.91    0.72    0.68    0.96    0.99    0.64
        0.98    0.84    0.88    0.67    0.65    0.88    0.56
0.93    0.77    0.59    0.79    0.92    0.92    0.78    0.76    0.89    0.63    0.91    0.52    0.55
        0.89    0.91    0.92    0.67    0.65    0.79    0.73
0.62    0.98    0.99    0.99    0.91    0.89    0.76    0.86    0.91    0.73    0.58    0.69    0.67
        0.72    0.54    0.77    0.92    0.58    0.69    0.5
0.96    0.76    0.74    0.67    0.69    0.93    0.81    0.59    0.89    0.74    0.57    0.56    0.83
        0.53    0.66    0.72    0.97    0.97    0.68    0.89
0.56    0.52    0.5     0.8     0.86    0.67    0.55    0.8     0.7     0.7     0.57    0.78    0.58
        0.99    0.52    0.62    0.7     0.78    0.65    0.97
0.98    0.96    0.68    0.99    0.89    0.85    0.58    0.99    0.67    0.82    0.94    0.86    0.99
        0.8     0.62    0.79    0.7     1       0.88    0.63
0.86    0.95    0.97    0.7     0.64    0.55    0.72    0.59    0.68    0.81    0.79    0.94    0.63
        0.73    0.97    0.6     0.58    0.56    0.97    0.72
0.52    0.89    0.58    0.64    0.68    0.81    0.67    0.67    0.81    0.9     0.53    0.68    0.57
        0.73    0.81    0.94    0.8     0.73    1       0.75
0.5     0.74    0.74    0.67    0.97    0.78    0.85    1       0.71    1       0.66    0.63    0.51
        0.86    0.8     0.94    0.75    0.55    0.89    0.6
0.66    0.73    0.73    0.75    0.87    0.74    0.76    0.67    0.9     0.82    0.69    0.94    0.99
        0.57    0.7     0.93    0.56    0.81    0.94    0.67
0.6     0.52    0.71    0.5     0.79    0.52    0.75    0.58    0.94    0.58    0.5     0.71    0.51
        0.62    0.79    0.59    0.87    0.88    0.97    0.71
0.66    0.87    0.73    0.78    0.73    0.96    0.9     0.8     0.62    0.84    0.88    0.6     0.52
        0.92    0.58    0.98    0.75    0.87    0.69    0.89
0.66    0.69    0.75    0.91    0.61    0.62    0.81    0.87    0.89    0.73    0.92    0.91    0.95
        0.74    0.71    0.88    0.85    0.53    0.86    0.56
0.73    0.53    0.59    0.73    0.52    0.91    0.51    0.63    0.72    0.66    0.53    0.56    0.52
        0.51    0.68    0.51    0.58    0.73    0.95    0.94
0.55    0.65    0.85    0.87    0.76    0.82    0.51    0.76    0.74    0.68    0.58    0.58    0.92
        0.53    0.79    0.8     0.77    0.58    0.77    0.81
```

0.87	0.56	0.7	0.83	0.94	0.7	0.83	0.81	0.91	0.84	0.71	0.61	0.98
	0.98	0.68	0.74	0.74	0.88	0.95	0.97					
0.94	0.95	0.54	0.59	0.96	1	0.78	0.91	0.67	0.83	0.9	0.6	0.95
	0.63	0.95	0.77	0.67	0.51	0.86	0.68					
0.83	0.89	0.99	0.88	0.54	0.94	0.59	0.62	0.6	0.53	0.72	0.52	1
	0.72	0.87	0.57	1	0.71	0.51	0.68					
0.6	0.94	0.64	0.88	0.86	0.95	0.7	0.91	1	0.53	0.82	0.75	0.6
	0.73	0.77	0.94	0.56	0.53	0.55	0.88					
0.5	0.97	0.94	0.69	0.68	0.73	0.94	0.76	0.64	0.66	0.84	0.66	0.76
	0.61	0.82	0.67	0.51	0.97	0.69	0.91					
0.62	0.99	0.63	0.65	0.6	0.78	0.8	0.55	0.67	0.66	0.71	0.67	0.63
	0.89	0.86	0.98	0.6	0.67	0.87	0.68					
0.8	0.64	0.64	0.57	0.65	0.99	0.52	0.75	0.92	0.88	0.58	0.6	0.79
	0.58	0.89	0.69	0.59	0.96	0.76	0.63					
0.76	0.95	1	0.57	0.6	0.93	0.56	0.72	0.66	0.75	0.5	0.5	0.91
	0.62	0.74	0.96	0.61	0.65	0.87	0.63					
0.77	0.9	0.87	0.87	0.54	0.93	0.61	0.76	0.7	0.86	0.9	0.95	0.74
	0.62	0.85	0.56	0.89	0.6	1	0.99					
0.61	0.7	0.9	0.76	0.69	0.87	0.63	0.71	0.68	0.98	0.52	0.92	0.62
	0.9	0.94	0.89	0.73	0.52	0.52	0.64					
0.75	0.54	0.86	0.77	0.61	0.96	0.71	0.69	0.72	0.9	0.51	0.87	0.75
	0.84	0.89	0.72	0.5	0.9	0.85	0.57					
0.6	0.79	0.67	0.6	0.79	0.65	0.81	0.75	0.53	0.68	0.76	0.86	0.89
	0.82	0.51	0.8	0.92	0.86	0.55	1					
0.6	0.93	0.96	0.86	0.9	0.61	0.89	0.76	0.72	0.78	0.8	0.62	0.72
	0.81	0.75	0.97	0.54	0.78	0.71	0.96					
0.75	0.73	0.84	0.81	0.94	0.75	0.59	0.89	0.58	0.71	0.76	0.99	0.85
	0.63	0.57	0.53	0.96	0.61	0.7	0.81					
0.8	0.93	0.55	0.61	0.57	0.85	0.69	0.93	0.95	0.98	0.83	0.66	0.94
	0.51	0.59	0.83	0.83	0.96	0.8	0.99					
0.71	0.79	0.97	0.64	0.61	0.62	0.52	0.77	0.89	0.55	0.57	0.65	0.77
	0.77	0.81	0.69	0.8	0.53	0.75	0.9					
0.58	0.52	0.92	0.6	0.74	0.53	0.51	0.77	0.6	0.77	0.53	0.86	0.74
	0.91	0.99	0.84	0.74	0.86	0.87	0.79					
0.52	0.57	0.99	0.78	0.63	0.83	0.82	0.74	0.76	0.78	0.98	0.78	0.6
	0.96	0.92	0.65	0.81	0.67	0.62	0.98					
0.78	0.53	0.73	0.67	0.91	0.59	0.64	0.95	0.61	0.71	0.56	0.51	0.52
	0.76	0.99	0.83	0.8	0.72	0.65	0.67					
0.88	0.62	0.75	0.69	0.6	0.89	0.69	0.82	0.6	0.6	0.74	0.5	0.53
	0.6	0.56	0.75	0.56	0.92	0.94	0.54					
0.93	0.56	0.61	0.51	0.93	0.78	0.66	0.74	0.83	0.65	0.76	0.71	0.86
	0.62	0.62	0.79	0.87	0.86	0.88	0.68					
0.98	0.67	0.83	0.89	0.81	0.97	0.52	0.72	0.99	0.91	0.99	0.59	0.58
	0.52	0.7	0.64	0.6	0.82	0.72	0.81					
0.78	0.52	0.81	0.81	0.74	0.68	0.87	0.92	0.9	0.96	0.89	0.73	0.63
	0.91	0.54	0.98	0.92	0.85	0.66	1					
0.98	0.69	0.56	0.64	0.79	0.98	0.59	0.95	0.72	0.99	0.61	0.73	0.58
	0.74	0.74	0.85	0.94	0.78	0.94	0.95					
0.59	0.69	0.54	0.54	0.7	0.89	0.64	0.74	0.79	0.62	0.73	0.89	0.84
	0.79	0.76	0.8	0.9	0.69	0.95	0.92					
0.54	0.67	0.58	0.94	0.67	0.86	0.59	0.78	0.64	0.68	0.94	0.79	0.97
	0.58	0.78	0.64	0.76	0.58	0.99	0.98					
0.53	0.62	0.93	0.6	0.68	0.68	0.98	0.86	0.63	0.54	0.78	0.97	0.8
	0.5	0.95	0.63	0.75	0.86	0.62	1					
0.81	0.88	0.9	0.61	0.89	0.95	0.74	0.62	0.82	0.6	0.89	0.73	0.52
	0.99	0.56	0.91	0.9	1	0.8	0.7					
0.99	0.77	0.76	0.58	0.79	0.87	0.94	0.65	0.97	0.75	0.79	0.89	0.51
	0.61	0.79	0.59	0.67	0.97	0.82	0.79					
0.77	0.72	0.5	0.74	0.55	0.92	0.85	0.89	0.69	0.58	0.77	0.97	0.73
	0.72	0.88	0.85	0.51	0.67	0.75	0.98					
0.51	0.76	0.87	0.79	0.84	0.9	0.61	0.5	0.88	0.72	0.77	0.81	0.78
	0.91	0.64	0.77	0.69	0.74	0.85	0.63					
0.92	0.8	0.55	0.72	0.68	0.73	0.7	0.62	0.55	0.82	0.85	0.58	0.95
	0.6	0.87	1	0.78	0.66	0.69	1					
0.52	0.81	0.89	0.66	0.94	0.9	0.67	0.77	0.71	0.57	0.62	0.68	0.82
	0.59	0.66	0.71	0.96	0.53	0.91	0.76					
0.66	0.51	0.89	0.68	0.64	0.75	0.79	0.61	0.9	0.63	0.73	0.51	0.55
	0.7	0.92	0.99	0.67	0.98	0.69	0.95					
0.97	0.89	0.56	0.88	0.53	0.6	0.99	0.96	0.69	0.82	0.69	0.89	0.67
	0.55	0.68	0.88	0.77	0.75	0.93	0.82					
0.62	0.89	0.72	0.5	0.82	0.77	0.5	0.89	0.56	0.94	0.54	0.78	0.57
	0.78	0.55	0.5	0.88	0.98	0.92	0.56					
0.63	0.99	0.96	0.71	0.52	0.61	0.57	0.94	0.59	0.96	0.56	0.68	0.84
	0.69	0.75	0.51	0.64	0.69	0.97	0.98					
0.68	0.96	0.68	0.93	0.58	0.55	0.94	0.98	0.69	0.71	0.65	0.63	0.56
	0.5	0.59	0.66	0.74	0.69	0.89	0.86					

```
0.92  0.93  0.78  0.87  0.98  0.59  0.75  0.61  0.88  0.76  0.9   0.69  0.93
      0.96  0.5   0.95  0.76  0.95  0.99  0.7
0.79  0.77  0.65  0.74  0.59  0.52  0.75  0.75  0.99  0.54  0.77  0.54  0.68
      0.53  0.57  0.53  0.91  0.86  0.79  0.88
0.52  0.74  0.53  0.88  0.67  0.53  0.84  0.58  0.52  0.78  0.65  0.84  0.89
      0.77  0.53  0.5   0.79  0.58  0.52  0.5
0.93  0.91  0.92  0.91  0.63  0.63  0.95  0.74  0.83  0.5   0.76  0.97  0.75
      0.87  0.79  0.66  0.86  0.88  0.62  0.51
0.79  0.94  0.78  0.65  0.73  0.83  0.69  0.52  0.57  0.9   0.89  0.95  0.8
      0.93  0.5   0.61  0.66  0.67  0.62  0.56
0.79  0.97  0.67  0.8   0.73  0.62  0.8   0.73  0.73  0.65  0.99  0.56  0.57
      0.99  0.91  0.64  0.9   0.92  0.83  0.6
0.65  0.53  0.65  0.59  0.8   0.8   0.68  0.51  0.99  0.65  0.61  0.71  0.63
      0.67  0.55  0.55  0.81  0.61  0.96  0.9
0.98  0.75  0.72  0.78  0.71  0.52  1     0.8   0.65  0.96  0.58  0.71  0.74
      0.9   0.53  0.71  0.73  0.78  0.76  0.8
0.9   0.92  0.85  0.71  0.8   0.69  0.9   0.99  0.88  0.9   0.9   0.84  0.68
      0.64  0.9   0.59  0.73  0.88  0.82  0.63
0.51  0.73  0.67  0.62  0.92  0.56  0.64  0.83  0.83  0.53  0.87  0.8   0.53
      0.55  0.84  0.88  0.84  0.85  0.62  0.84
0.78  0.99  0.67  0.51  0.86  0.61  0.92  0.79  0.53  0.85  0.84  0.5   0.87
      0.78  0.61  0.7   0.66  0.6   0.76  1
0.78  0.62  0.79  1     0.83  0.66  0.59  0.71  1     0.64  0.68  0.94  0.93
      0.94  0.92  0.5   0.99  0.92  0.58  0.65
1     0.56  0.83  0.87  0.99  0.58  0.53  1     0.67  0.51  0.61  0.53  0.73
      0.52  0.73  0.51  0.84  0.64  0.74  0.63
0.71  0.6   1     0.51  0.88  0.99  0.74  0.58  0.85  0.7   0.75  0.82  0.89
      0.62  0.69  0.66  0.92  0.65  0.6   0.56
0.6   0.75  0.89  0.77  0.73  0.77  0.77  0.99  0.83  0.79  0.51  0.66  0.86
      0.96  0.8   1     0.95  0.84  0.94  0.68
0.6   0.93  0.63  0.69  0.78  0.89  0.92  0.86  0.84  0.92  0.59  0.76  0.65
      1     0.6   0.89  0.67  0.75  0.6   0.57
0.69  0.6   0.94  0.5   0.92  0.75  0.69  0.96  0.67  0.83  0.59  0.87  0.87
      0.72  0.71  0.64  0.99  0.5   0.97  0.71
0.53  0.7   0.55  0.72  0.52  0.92  0.92  0.52  0.75  0.99  0.62  0.72  0.85
      0.57  0.8   0.7   0.81  0.78  0.8   0.82
0.56  0.7   0.58  0.7   0.65  0.6   0.88  0.54  1     0.66  0.92  0.95  0.54
      0.96  0.83  0.67  0.7   0.95  0.76  0.94
0.77  0.97  0.71  0.98  0.72  0.85  0.57  0.96  0.81  0.51  0.8   0.75  0.91
      0.92  0.61  0.52  0.73  0.71  0.75  0.89
0.89  0.56  0.71  0.81  0.52  0.81  0.73  0.69  0.52  0.61  0.78  0.67  0.79
      0.7   0.83  0.95  0.92  0.52  0.62  0.91
0.66  0.83  0.71  0.96  0.5   0.96  0.63  0.76  0.9   0.88  0.68  0.56  0.6
      0.88  0.86  0.92  0.74  0.82  0.84  0.7
0.76  0.89  0.89  0.73  0.66  0.79  0.94  0.89  0.72  0.81  0.8   0.88  0.73
      0.97  1     0.58  0.5   0.79  0.77  0.58
0.62  0.71  0.6   0.7   0.72  0.56  0.55  0.94  0.7   0.97  0.84  0.77  0.85
      0.58  0.6   0.52  0.91  0.55  0.68  0.86
0.66  0.94  1     0.69  0.59  0.87  0.54  0.68  0.78  0.66  0.72  0.63  0.94
      1     0.73  0.98  0.99  0.77  0.64  0.77
0.89  0.87  0.72  0.9   0.59  0.7   0.55  0.81  0.89  0.62  0.56  0.65  0.63
      0.7   0.75  0.73  0.85  0.51  0.62  0.57
0.75  0.53  0.75  0.89  0.86  0.75  0.77  0.86  0.67  0.81  0.82  0.93  0.83
      0.79  0.68  0.9   0.9   0.94  0.88  0.77
0.55  0.55  0.71  0.56  0.85  0.93  0.57  0.77  0.96  0.8   0.55  0.8   0.87
      0.62  0.64  0.58  0.91  0.96  0.58  0.72
0.91  0.92  0.52  0.6   0.63  0.5   0.77  0.76  0.93  0.68  1     0.68  0.94
      0.96  0.99  0.51  0.79  0.69  0.8   1
0.5   0.66  0.88  0.57  0.58  0.77  0.7   0.75  0.57  0.93  0.89  1     0.69
      0.61  0.94  0.61  0.51  0.57  0.79  0.66
0.53  0.95  0.99  0.62  0.69  0.55  0.73  0.59  0.87  0.82  0.79  0.94  0.73
      0.83  0.95  0.57  0.93  0.99  0.57  0.69
0.81  0.97  0.64  0.55  0.52  0.61  0.65  0.58  0.85  0.88  0.84  0.89  0.97
      0.62  0.57  0.66  0.71  0.88  0.64  0.55
0.88  0.95  0.7   0.51  0.98  0.55  0.68  0.69  0.5   0.66  0.55  0.64  0.87
      0.64  0.98  0.56  0.85  0.58  0.5   0.63
0.76  0.98  0.65  0.94  0.93  0.74  0.66  0.7   0.97  0.99  0.94  0.5   0.9
      0.81  0.57  0.84  0.62  0.64  0.57  0.57
0.57  0.84  0.97  0.76  0.87  0.61  0.77  0.78  0.75  0.74  0.7   0.74  0.88
      0.59  0.87  0.64  0.91  0.96  0.88  1
/

SUMMARY
FPR
WBHP
/
FOPR
```

```
FWPR
FOPT
FWPT
FWCT
FOE
FTPRHTO
FTPRPR1
FTPRPR2
FTPRPR3
FTPRPR4
-- tracer prod rate

FTPTHTO
FTPTPR1
FTPTPR2
FTPTPR3
FTPTPR4
-- tracer total production

FTIRHTO
FTIRPR1
FTIRPR2
FTIRPR3
FTIRPR4
-- tracer inj rate

FTITHTO
FTITPR1
FTITPR2
FTITPR3
-- tracer total injection

FTPCHTO
FTPCPR1
FTPCPR2
FTPCPR3
FTPCPR4
-- tracer prod concentration

FTICHTO
FTICPR1
FTICPR2
FTICPR3
FTICPR4
-- tracer inj concentration

FTIPTHTO
FTIPTPRT
-- tracer in place (total)

FTIPFHTO
FTIPFPR1
FTIPFPR2
FTIPFPR3
FTIPFPR4
-- tracer in place (free)

FTIPSPR1
FTIPSPR2
FTIPSPR3
FTIPSPR4
-- tracer in place (solution)

FTIRFHTO
FTIRFPR1
FTIRFPR2
FTIRFPR3
FTIRFPR4

FTIRSPR1
FTIRSPR2
FTIRSPR3
FTIRSPR4
-- tracer inj rate (free and solution)

FTPRFHTO
FTPRFPR1
```

```
FTPRFPR2
FTPRFPR3
FTPRFPR4

FTPRSPR1
FTPRSPR2
FTPRSPR3
FTPRSPR4
-- tracer prod rate (free & solution)

FTICFHTO
FTICFPR1
FTICFPR2
FTICFPR3
FTICFPR4

FTICSPR1
FTICSPR2
FTICSPR3
FTICSPR4
-- tracer inj concentration (free

FTPCFHTO
FTPCFPR1
FTPCFPR2
FTPCFPR3
FTPCFPR4

FTPCSPR1
FTPCSPR2
FTPCSPR3
FTPCSPR4

FOSAT
-- average oil saturation
FWSAT

--BWSAT
FWIR
FWPR
FWIPR
FWIPT

TCPU
EXCEL

SCHEDULE

TUNING
/
/
2* 200 /

WELSPECS
PROD1 G1 100 20 8045 OIL /
INJ1 G2 1 1 8045 WATER /
/

COMPDAT
PROD1 100 20 1 1 OPEN 2* 0.3333 /
INJ1 1 1 1 1 OPEN 2* 0.3333 /
-- 4 in production tubing
 /

WCONPROD
'PROD1' OPEN LRAT 3* 1500 1* 3500 /
-- 7000 STB/D LIQUID RATE
-- 9th item is lowermost BHP, which is the hydrostatic (ñ=63)
/

WCONINJE
 'INJ1' WATER OPEN RATE 1500 /
/

TIME
1 /
```

```
WTRACER
INJ1 HTO 1 /
INJ1 PR1 1 /
INJ1 PR2 1 /
INJ1 PR3 1 /
INJ1 PR4 1 /
/

TIME
2 /

WTRACER
INJ1 HTO 0 /
INJ1 PR1 0 /
INJ1 PR2 0 /
INJ1 PR3 0 /
INJ1 PR4 0 /
/

TSTEP
50*0.0001 0.0003 0.0005 0.0007 0.0009 0.001 0.003 0.005 0.007 0.009 0.01 0.03 0.05 0.07 0.09
0.1 0.3 0.5 0.7 0.9 10*1.3 920*3.5 /

END
```

-- Mobile Oil (different tracer per connection)

```
RUNSPEC

TITLE
-- Tracers' Injection Model 600*600*60 ft^3 reservoir

DIMENS
600 1 3 /
-- cubic block of 2*600*20 ft^3
OIL
WATER

NSTACK
100 /

NUPCOL
4 /

FIELD

TRACERS
-- info in terms of passive tracers being used
1* 15 2* DIFF 50 3 /

START
18 JUL 2018 /
WELLDIMS
2 3 2 1 /

UNIFOUT

PARTTRAC
-- Max no of partitioned tracers, No of K(p) tables in TRACERKP, Max no of pres points in K(p)
in TRACERKP
12 4 2 /

GRID

DX
1800*1 /

DY
1800*600 /

DZ
1800*20 /

BOX
1 600 1 1 1 1 /

TOPS
600*8000 /
-- depth of top blocks arbitrarily taken at 8000 ft
ENDBOX

BOX
1 600 1 1 1 3 /
PORO
1800*0.25 /
ENDBOX

BOX
1 600 1 1 1 3 /
PERMX
600*400
600*1000
600*600 /
ENDBOX

BOX
1 600 1 1 1 3 /
PERMY
600*400
600*1000
600*600 /
```

```
ENDBOX

BOX
1 600 1 1 1 3 /
PERMZ
600*40
600*100
600*60 /
ENDBOX

INIT

EDIT

PROPS

TRACER
-- tracer name, WAT, 'STB', Sol Phase, No of K(P) table,
HTA WAT /
HTB WAT /
HTC WAT /
P1A WAT 1* OIL 1 /
P1B WAT 1* OIL 1 /
P1C WAT 1* OIL 1 /
P2A WAT 1* OIL 2 /
P2B WAT 1* OIL 2 /
P2C WAT 1* OIL 2 /
P3A WAT 1* OIL 3 /
P3B WAT 1* OIL 3 /
P3C WAT 1* OIL 3 /
P4A WAT 1* OIL 4 /
P4B WAT 1* OIL 4 /
P4C WAT 1* OIL 4 /
/

TRACERKP
-- P (increasing), Partition Coefficient
14.7 0.5
4500 0.5
/
14.7 1
4500 1
/
14.7 1.5
4500 1.5
/
14.7 2
4500 2
/

PVDO
-- P Bo ì
300 1.25 1.0
800 1.20 1.1
6000 1.15 2.0 /

DENSITY
-- ño(s.c) ñw(s.c) ñg(s.c)
49 63 0.01 /

PVTW
-- Pref Bw Cw ìW viscosibility(usually 0)
4500 1.02 3.0E-06 0.8 0.0 /

ROCK
-- Pref C
4500 4E-06 /

SWOF
-- Sw Krw Kro Pcwo
0.2 0.0 0.6 3
0.24 0.00032 0.47 2.6
0.28 0.000504 0.36 2.2
0.32 0.0026 0.27 1.8
0.35 0.0081 0.2 1.4
0.39 0.02 0.14 1
0.43 0.041 0.1 0.8
```

```
0.47 0.076 0.06 0.6
0.51 0.13 0.03 0.4
0.55 0.21 0.0175 0.2
0.58 0.32 0.007 0.1
0.62 0.46 0.0022 0
0.66 0.65 0 0
0.7 0.9 0 0 /


REGIONS

TRKPFP1A
1800*1 /
TRKPFP1B
1800*1 /
TRKPFP1C
1800*1 /
TRKPFP2A
1800*2 /
TRKPFP2B
1800*2 /
TRKPFP2C
1800*2 /
TRKPFP3A
1800*3 /
TRKPFP3B
1800*3 /
TRKPFP3C
1800*3 /
TRKPFP4A
1800*4 /
TRKPFP4B
1800*4 /
TRKPFP4C
1800*4 /

SOLUTION

PRESSURE
1800*4500 /

DATUM
8060 /

TVDPFHTA
8000 0.0
8060 0.0 /

TVDPFHTB
8000 0.0
8060 0.0 /

TVDPFHTC
8000 0.0
8060 0.0 /

TVDPFP1A
8000 0.0
8060 0.0 /

TVDPFP1B
8000 0.0
8060 0.0 /

TVDPFP1C
8000 0.0
8060 0.0 /

TVDPFP2A
8000 0.0
8060 0.0 /

TVDPFP2B
8000 0.0
8060 0.0 /

TVDPFP2C
```

```
8000 0.0
8060 0.0 /

TVDPFP3A
8000 0.0
8060 0.0 /

TVDPFP3B
8000 0.0
8060 0.0 /

TVDPFP3C
8000 0.0
8060 0.0 /

TVDPFP4A
8000 0.0
8060 0.0 /

TVDPFP4B
8000 0.0
8060 0.0 /

TVDPFP4C
8000 0.0
8060 0.0 /

SWAT
1800*0.25 /

SUMMARY
FPR
WBHP
/
FOPR
FWPR
FOPT
FWPT
FWCT
FOE
FWSAT
FWPR
FWIPR
FWIPT

CTPCHTA
'PROD1' 600 1 1 /
/

CTPCHTB
'PROD1' 600 1 2 /
/

CTPCHTC
'PROD1' 600 1 3 /
/

CTPCP1A
'PROD1' 600 1 1 /
/

CTPCP1B
'PROD1' 600 1 2 /
/

CTPCP1C
'PROD1' 600 1 3 /
/

CTPCP2A
'PROD1' 600 1 1 /
/

CTPCP2B
'PROD1' 600 1 2 /
/
```

```
CTPCP2C
'PROD1' 600 1 3 /
/

CTPCP3A
'PROD1' 600 1 1 /
/

CTPCP3B
'PROD1' 600 1 2 /
/

CTPCP3C
'PROD1' 600 1 3 /
/

CTPCP4A
'PROD1' 600 1 1 /
/

CTPCP4B
'PROD1' 600 1 2 /
/

CTPCP4C
'PROD1' 600 1 3 /
/

COPR
'PROD1' 600 1 1 /
'PROD1' 600 1 2 /
'PROD1' 600 1 3 /
/

CWPR
'PROD1' 600 1 1 /
'PROD1' 600 1 2 /
'PROD1' 600 1 3 /
/

COPT
'PROD1' 600 1 1 /
'PROD1' 600 1 2 /
'PROD1' 600 1 3 /
/

FTPCHTA
FTPCHTB
FTPCHTC
FTPCP1A
FTPCP1B
FTPCP1C
FTPCP2A
FTPCP2B
FTPCP2C
FTPCP3A
FTPCP3B
FTPCP3C
FTPCP4A
FTPCP4B
FTPCP4C

TCPU
EXCEL

SCHEDULE

TUNING
/
/
2* 100 /

WELSPECS
PROD1 G1 600 1 8000 OIL /
INJ1 G2 1 1 8000 WATER /
/
```

```
COMPDAT
PROD1 600 1 1 3 OPEN 2* 0.3333 /
INJ1 1 1 1 3 OPEN 2* 0.3333 /
-- 4 in production tubing
 /

WCONPROD
'PROD1' OPEN LRAT 3* 1000 1* 3500 /
-- 7000 STB/D LIQUID RATE
-- 9th item is lowermost BHP, which is the hydrostatic (ñ=63)
/

WCONINJE
 'INJ1' WATER OPEN RATE 1000 /
/

TIME
1 /

WELOPEN
INJ1 OPEN 0 0 1 /
INJ1 SHUT 0 0 2 /
INJ1 SHUT 0 0 3 /
/

WTRACER
INJ1 HTA 1 /
INJ1 P1A 1 /
INJ1 P2A 1 /
INJ1 P3A 1 /
INJ1 P4A 1 /
/

TIME
2 /

WTRACER
INJ1 HTA 0 /
INJ1 P1A 0 /
INJ1 P2A 0 /
INJ1 P3A 0 /
INJ1 P4A 0 /
/

WELOPEN
INJ1 SHUT 0 0 1 /
INJ1 OPEN 0 0 2 /
INJ1 SHUT 0 0 3 /
/

WTRACER
INJ1 HTB 1 /
INJ1 P1B 1 /
INJ1 P2B 1 /
INJ1 P3B 1 /
INJ1 P4B 1 /
/

TIME
3 /

WTRACER
INJ1 HTB 0 /
INJ1 P1B 0 /
INJ1 P2B 0 /
INJ1 P3B 0 /
INJ1 P4B 0 /
/

WELOPEN
INJ1 SHUT 0 0 1 /
INJ1 SHUT 0 0 2 /
INJ1 OPEN 0 0 3 /
/

WTRACER
INJ1 HTC 1 /
```

```
INJ1 P1C 1 /
INJ1 P2C 1 /
INJ1 P3C 1 /
INJ1 P4C 1 /
/

TIME
4 /

WTRACER
INJ1 HTC 0 /
INJ1 P1C 0 /
INJ1 P2C 0 /
INJ1 P3C 0 /
INJ1 P4C 0 /
/

TIME
5 /

WELOPEN
INJ1 OPEN 0 0 0 /
/

TSTEP
48*0.0001 945*7 /


END
```

-- Dual Permeability Model

```
RUNSPEC

TITLE
-- Tracers' Injection Model 200*200*30 ft^3 reservoir

DIMENS
4 4 8 /
-- cubic block of 12*12*10 ft^3
OIL
WATER

DUALPORO

DUALPERM

NSTACK
250 /

NUPCOL
4 /

TABDIMS
2 /

FIELD

TRACERS
1* 5 2* DIFF 50 3 /

START
18 JUL 2018 /
WELLDIMS
2 8 2 1 /

UNIFOUT

PARTTRAC
4 4 2 /

ENDSCALE
DIRECT IRREVERS /

GRID

NODPPM
--no dual porosity multiplier

DPGRID
DX
128*10 /

DY
128*10 /

DZ
128*10 /


BOX
1 4 1 4 1 1 /

TOPS
16*8000 /
ENDBOX

BOX
1 4 1 4 1 8 /
PORO
64*0.15
64*0.002 /
ENDBOX

BOX
1 4 1 4 1 8 /
```

```
PERMX
64*0.5
64*5000 /
ENDBOX

BOX
1 4 1 4 1 8 /
PERMY
64*0.5
64*5000 /
ENDBOX

BOX
1 4 1 4 1 8 /
PERMZ
64*0.05
64*0.05 /
ENDBOX

SIGMA
0.12 /

INIT

EDIT

PROPS

TRACER
-- tracer name, WAT, 'STB', Sol Phase, No of K(P) table,
HTO WAT /
PR1 WAT 1* OIL 1 /
PR2 WAT 1* OIL 1 /
PR3 WAT 1* OIL 1 /
PR4 WAT 1* OIL 1 /
/

TRACERKP
-- P (increasing), Partition Coefficient
14.7 0.5
4500 0.5
/
14.7 1
4500 1
/
14.7 1.5
4500 1.5
/
14.7 2
4500 2
/

--TRACITVD
--1 /


PVDO
-- P Bo ì
300 1.25 0.8
800 1.20 1
6000 1.15 1.8 /

DENSITY
49 63 0.01 /

PVTW
4500 1.02 3.0E-06 1 0.0 /

ROCK
-- Pref Cs
4500 4E-06 /

SWOF
-- Sw Krw Kro Pcwo
0.2 0.0 0.95 4
0.3 0.1 0.8 3
0.4 0.2 0.65 2.2
```

```
0.5 0.3 0.4 1.6
0.6 0.4 0.2 1
0.7 0.5 0 0.6
0.75 0.6 0 0.2
0.8 0.7 0 0
0.9 0.8 0 0
1 0.9 0 0 /
0.2 0.0 0.95 0
0.3 0.1 0.8 0
0.4 0.2 0.65 0
0.5 0.3 0.4 0
0.6 0.4 0.2 0
0.7 0.5 0 0
0.75 0.6 0 0
0.8 0.7 0 0
0.9 0.8 0 0
1 0.9 0 0 /


REGIONS
SATNUM
64*1 64*2 /

TRKPFPR1
128*1 /
TRKPFPR2
128*2 /
TRKPFPR3
128*3 /
TRKPFPR4
128*4 /


SOLUTION

PRESSURE
128*4500 /

DATUM
8060 /

TVDPFHTO
8000 0.0
8030 0.0 /

TVDPFPR1
8000 0.0
8030 0.0 /

TVDPFPR2
8000 0.0
8030 0.0 /

TVDPFPR3
8000 0.0
8030 0.0 /

TVDPFPR4
8000 0.0
8030 0.0 /

SWAT
128*0.25 /

SUMMARY
FPR
WBHP
/
FOPR
FWPR
FOPT
FWPT
FWCT
FOE
FTPRHTO
FTPRPR1
FTPRPR2
```

```
FTPRPR3
FTPRPR4
-- tracer prod rate

FTPTHTO
FTPTPR1
FTPTPR2
FTPTPR3
FTPTPR4
-- tracer total production

FTIRHTO
FTIRPR1
FTIRPR2
FTIRPR3
FTIRPR4
-- tracer inj rate

FTITHTO
FTITPR1
FTITPR2
FTITPR3
-- tracer total injection

FTPCHTO
FTPCPR1
FTPCPR2
FTPCPR3
FTPCPR4
-- tracer prod concentration

FTICHTO
FTICPR1
FTICPR2
FTICPR3
FTICPR4
-- tracer inj concentration

FTIPTHTO
FTIPTPRT
-- tracer in place (total)

FTIPFHTO
FTIPFPR1
FTIPFPR2
FTIPFPR3
FTIPFPR4
-- tracer in place (free)

FTIPSPR1
FTIPSPR2
FTIPSPR3
FTIPSPR4
-- tracer in place (solution)

FTIRFHTO
FTIRFPR1
FTIRFPR2
FTIRFPR3
FTIRFPR4

FTIRSPR1
FTIRSPR2
FTIRSPR3
FTIRSPR4
-- tracer inj rate (free and solution)

FTPRFHTO
FTPRFPR1
FTPRFPR2
FTPRFPR3
FTPRFPR4

FTPRSPR1
FTPRSPR2
FTPRSPR3
FTPRSPR4
```

```
-- tracer prod rate (free & solution)

FTICFHTO
FTICFPR1
FTICFPR2
FTICFPR3
FTICFPR4

FTICSPR1
FTICSPR2
FTICSPR3
FTICSPR4
-- tracer inj concentration (free

FTPCFHTO
FTPCFPR1
FTPCFPR2
FTPCFPR3
FTPCFPR4

FTPCSPR1
FTPCSPR2
FTPCSPR3
FTPCSPR4
-- tracer prod concentration (free & solution)
FWSAT

CTPCHTO
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

CTPCPR1
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

CTPCPR2
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

CTPCPR3
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

CTPCPR4
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
```

```
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

CWPT
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

COPT
'PROD1' 4 4 1 /
'PROD1' 4 4 2 /
'PROD1' 4 4 3 /
'PROD1' 4 4 4 /
'PROD1' 4 4 5 /
'PROD1' 4 4 6 /
'PROD1' 4 4 7 /
'PROD1' 4 4 8 /
/

--BWSAT
EXCEL

SCHEDULE

RPTRST
 BASIC=2 NORTST=1 /

TUNING
/
/
2* 250 1* 20 /

WELSPECS
PROD1 G1 4 4 8000 OIL /
INJ1 G2 1 1 8000 WATER /
/

COMPDAT
PROD1 4 4 1 8 OPEN 2* 0.3333 /
INJ1 1 1 1 8 OPEN 2* 0.3333 /
/

WCONPROD
'PROD1' OPEN LRAT 3* 50 1* 3500 /
/

WCONINJE
 'INJ1' WATER OPEN RATE 50 /
/

TIME
1 /

WTRACER
INJ1 HTO 1 /
INJ1 PR1 1 /
INJ1 PR2 1 /
INJ1 PR3 1 /
INJ1 PR4 1 /
/

TIME
2 /

WTRACER
INJ1 HTO 0 /
INJ1 PR1 0 /
INJ1 PR2 0 /
INJ1 PR3 0 /
```

```
INJ1 PR4 0 /
/

TSTEP
48*0.0001 50*0.001 400*3 500*12 /

END
```

-- Discrete Fracture Model

```
RUNSPEC

TITLE
-- Tracers' Injection Model 200*200*30 ft^3 reservoir

DIMENS
14 14 14 /
-- cubic block of 12*12*10 ft^3
OIL
WATER


NSTACK
500 /

NUPCOL
7 /

TABDIMS
2 /

FIELD

TRACERS
1* 5 2* DIFF 50 3 /

START
18 JUL 2018 /
WELLDIMS
2 14 2 1 /

UNIFOUT

PARTTRAC
4 4 2 /

ENDSCALE
DIRECT IRREVERS /

GRID

DX
2744*4.625 /

DY
2744*4.625 /

DZ
2744*4.625 /

BOX
1 14 1 14 1 1 /

TOPS
196*8000 /
ENDBOX

BOX
1 14 1 14 1 14 /
PORO
2744*0.15 /
ENDBOX

BOX
1 14 1 14 1 14 /
PERMX
2744*0.5 /
ENDBOX

BOX
1 14 1 14 1 14 /
PERMY
2744*0.5 /
ENDBOX
```

```
BOX
1 14 1 14 1 14 /
PERMZ
2744*0.05 /
ENDBOX

EQUALS
PORO 0.1 1 14 1 14 3 4 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DZ 0.5 /

PORO 0.1 1 14 1 14 7 8 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DZ 0.5 /

PORO 0.1 1 14 1 14 11 12 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DZ 0.5 /

PORO 0.1 3 4 1 14 1 14 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DX 0.5 /

PORO 0.1 7 8 1 14 1 14 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DX 0.5 /

PORO 0.1 11 12 1 14 1 14 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DX 0.5 /

PORO 0.1 1 14 3 4 1 14 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DY 0.5 /

PORO 0.1 1 14 7 8 1 14 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DY 0.5 /

PORO 0.1 1 14 11 12 1 14 /
PERMX 5000 /
PERMY 5000 /
PERMZ 500 /
DY 0.5 /
/

INIT

EDIT

PROPS

TRACER
HTO WAT /
PR1 WAT 1* OIL 1 /
PR2 WAT 1* OIL 1 /
PR3 WAT 1* OIL 1 /
PR4 WAT 1* OIL 1 /
/
```

```
TRACERKP
-- P (increasing), Partition Coefficient
14.7 0.5
4500 0.5
/
14.7 1
4500 1
/
14.7 1.5
4500 1.5
/
14.7 2
4500 2
/

PVDO
-- P Bo ì
300 1.25 0.8
800 1.20 1
6000 1.15 1.8 /

DENSITY
-- ño(s.c) ñw(s.c) ñg(s.c)
49 63 0.01 /

PVTW
4500 1.02 3.0E-06 1 0.0 /

ROCK
-- Pref Cs
4500 4E-06 /

SWOF
-- Sw Krw Kro Pcwo
0.2 0.0 0.95 4
0.3 0.1 0.8 3
0.4 0.2 0.65 2.2
0.5 0.3 0.4 1.6
0.6 0.4 0.2 1
0.7 0.5 0 0.6
0.75 0.6 0 0.2
0.8 0.7 0 0
0.9 0.8 0 0
1 0.9 0 0 /
0.2 0.0 0.95 0
0.3 0.1 0.8 0
0.4 0.2 0.65 0
0.5 0.3 0.4 0
0.6 0.4 0.2 0
0.7 0.5 0 0
0.75 0.6 0 0
0.8 0.7 0 0
0.9 0.8 0 0
1 0.9 0 0 /


REGIONS
SATNUM
2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2
```

```
2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

196*2 196*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

196*2 196*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

196*2 196*2
```

```
2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1
14*2 14*2

2*1 2*2 2*1 2*2 2*1 2*2 2*1
2*1 2*2 2*1 2*2 2*1 2*2 2*1 /

TRKPFPR1
2744*1 /
TRKPFPR2
2744*2 /
TRKPFPR3
2744*3 /
TRKPFPR4
2744*4 /

SOLUTION

PRESSURE
2744*4500 /

DATUM
8060 /

TVDPFHTO
8000 0.0
8400 0.0 /

TVDPFPR1
8000 0.0
8400 0.0 /

TVDPFPR2
8000 0.0
8400 0.0 /

TVDPFPR3
8000 0.0
8400 0.0 /

TVDPFPR4
8000 0.0
8400 0.0 /

SWAT
2744*0.25 /

SUMMARY
FPR
WBHP
/
FOPR
FWPR
FOPT
```

```
FWPT
FWCT
FOE
FTPCHTO
FTPCPR1
FTPCPR2
FTPCPR3
FTPCPR4
FTICSPR1
FTICSPR2
FTICSPR3
FTICSPR4
FTPCFHTO
FTPCFPR1
FTPCFPR2
FTPCFPR3
FTPCFPR4

FOSAT
FWSAT

CTPCHTO
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

CTPCPR1
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

CTPCPR2
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

CTPCPR3
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
```

```
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

CTPCPR4
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

CWPT
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

COPT
'PROD1' 14 14 1 /
'PROD1' 14 14 2 /
'PROD1' 14 14 3 /
'PROD1' 14 14 4 /
'PROD1' 14 14 5 /
'PROD1' 14 14 6 /
'PROD1' 14 14 7 /
'PROD1' 14 14 8 /
'PROD1' 14 14 9 /
'PROD1' 14 14 10 /
'PROD1' 14 14 11 /
'PROD1' 14 14 12 /
'PROD1' 14 14 13 /
'PROD1' 14 14 14 /
/

BVELWI
1 1 1 /
1 1 2 /
1 1 3 /
1 1 4 /
1 1 5 /
1 1 6 /
1 1 7 /
1 1 8 /
1 1 9 /
1 1 10 /
1 1 11 /
1 1 12 /
1 1 13 /
```

```
1 1 14 /
1 2 1 /
1 5 1 /
1 14 1 /
3 1 1 /
3 7 1 /
3 12 1 /
5 1 1 /
5 5 5 /
/

--BWSAT
EXCEL

SCHEDULE

RPTRST
 BASIC=2 NORTST=1 /

TUNING
/
/
2* 500 1* 30 /

WELSPECS
PROD1 G1 14 14 8000 OIL /
INJ1 G2 1 1 8000 WATER /
/

COMPDAT
PROD1 14 14 1 14 OPEN 2* 0.3333 /
INJ1 1 1 1 14 OPEN 2* 0.3333 /
/

WCONPROD
'PROD1' OPEN LRAT 3* 50 1* 3500 /

WCONINJE
 'INJ1' WATER OPEN RATE 50 /
/

TIME
1 /

WTRACER
INJ1 HTO 1 /
INJ1 PR1 1 /
INJ1 PR2 1 /
INJ1 PR3 1 /
INJ1 PR4 1 /
/

TIME
2 /

WTRACER
INJ1 HTO 0 /
INJ1 PR1 0 /
INJ1 PR2 0 /
INJ1 PR3 0 /
INJ1 PR4 0 /
/


TSTEP
48*0.0001 50*0.001 400*1 /

END
```

Appendix C

-- Random Distribution INPUT file (UTCHEM)

```
CC*******************************************************************
CC                                                                  *
CC BRIEF DESCRIPTION OF DATA SET : UTCHEM (VERSION 11.7)            *
CC                                                                  *
CC*******************************************************************
CC                                                                  *
CC 1-D Quarter of a 5-spot                                          *
CC                                                                  *
CC OUTER RADIUS (FT): PROCESS : TRACER INJECTION                     *
CC THICKNESS (FT): INJ. RATE (FT3/DAY) :8590.3 CFT/D = 1500 STB/D   *
CC COORDINATES: Cartesian                                           *
CC POROSITY: 0.25 VERTICAL WELL                                     *
CC GRID BLOCKS: 100x20x1 (1-D)                                      *
CC DATE:19 July 2018                                                *
CC                                                                  *
CC*******************************************************************
CC
CC*******************************************************************
CC                                                                  *
CC RESERVOIR DESCRIPTION                                            *
CC                                                                  *
CC*******************************************************************
CC
CC
*----RUNNO
RUN001
CC
CC
*----TITLE
2-D reservoir single-phase flow (at Sor)
to be compared with the corresponding model
generated in ECLIPSE
CC
CC
*---- IMODE IMES IDISPC ICWM ICAP IREACT IBIO ICOORD ITREAC ITC IGAS IENG
1    4     3     0    0    0      0     1      0     0    0   0
CC
CC
*----NX NY NZ IDXYZ IUNIT
100 20  1   0     0
CC
CC grid block size (constant)
*---- DX1      DY1     DZ1
10      50      90
CC
CC total no of components & tracers
*----N NO NTW NTA NFC NG NOTH
13 0  5   0   0  0    0
CC
CC components' names
*---- from i=1 to n
Water
Oil
Surf.
Polymer
Chloride
Calcium
Alcohol 1
Alcohol 2
Passive
PRT1
PRT2
PRT3
PRT4
CC
CC indication whether component is included in the calculations (oil, water and passive
tracer)
```

```
*----
1 1 0 0 0 0 0 0 1 1 1 1 1
CC
CC*******************************************************************
CC                                                                  *
CC OUTPUT OPTIONS                                                   *
CC                                                                  *
CC*******************************************************************
CC
CC
CC days or pore volumes intervals
*---- ICUMTM ISTOP IOUTGMS IS3GRF
0      0      0       0
CC
CC whether the profile of the KCth component should be written or not
*----IRRFLG(KC)
1 1 0 0 0 0 0 0 1 1 1 1 1
CC
CC pressure, saturation, temp profiles
*----IPPRES IPSAT IPCTOT IPBIO IPCAP IPGEL IPALK IPTEMP IPOBS
0      1            1    0      0     0     0     0      1
CC
CC whether some properties should be included
*----ICKL IVIS IPER ICNM ICSE IHYSTP IFOAMP INONEQ
1    0    0    0    0     0      0      0
CC
CC
*----IADS IVEL IRKF IPHSE
0    1    0     0
CC
CC No of observation points (IOBS=1)
*----NOBS
1
CC
CC
*----IOBS(I) JOBS(I) KOBS(I)
1 1 1
CC
CC*******************************************************************
CC                                                                  *
CC RESERVOIR PROPERTIES                                             *
CC                                                                  *
CC*******************************************************************
CC
CC
CC maximum simulation time (days)
*----Tmax
3000
CC
CC rock compressibility
*----CMOPR PSTAND
0.0000004 4500
CC
CC constant, varying etc. type of porosity
*----IPOR1 IPERMX IPERMY IPERMZ IMOD TRANZ INTG
0      0      0      0     0    0     0
CC
CC constant porosity value
*---- PORC1
0.25
CC
CC constant X permeability
*----PERMXC
1000
CC
CC constant Y permeability
*----PERMYC
1000
CC
CC constant Z permeability
*----PERMZC
100
CC
CC Initial Reservoir/Aquifer data
*----IDEPTH IPRESS ISWI ICWI
0      0      2    -1
CC
```

```
CC depth of top block (equivalent to Eclipse's TOPS)
*----D1111
8000
CC
CC Pressure for all blocks (constant)
*----PRESS1
4500
CC
CC Water Saturation
*----
0.81	0.5	0.85	0.92	0.92	0.63	0.53	0.97	0.72	0.76	0.5	0.52	1
	0.73	0.6	0.97	0.71	0.8	1	0.74
0.63	0.78	0.53	0.54	0.63	0.62	0.83	0.52	0.79	0.52	0.93	0.86	0.76
	0.95	0.93	0.94	0.86	0.95	0.6	0.69
0.93	0.96	0.9	0.82	0.82	0.65	0.93	0.98	0.61	1	0.94	0.77	0.81
	0.87	0.88	0.6	0.79	0.58	0.9	0.92
0.95	0.7	0.69	0.82	0.78	0.72	0.71	0.82	0.95	0.87	0.55	0.88	0.78
	0.99	0.62	0.88	0.98	0.73	0.57	0.88
0.65	0.87	0.62	0.8	1	0.5	0.54	0.53	0.99	0.7	0.66	0.74	0.7
	0.8	0.5	0.52	0.99	0.98	0.78	0.66
0.66	0.99	0.8	0.96	0.53	0.7	0.92	0.66	0.9	0.52	0.86	0.51	0.94
	0.96	0.92	0.5	0.91	0.93	0.54	0.52
0.77	0.96	0.63	0.57	0.92	1	0.67	0.77	1	0.91	0.69	0.54	0.51
	0.83	0.63	0.54	0.82	0.76	0.88	0.79
0.87	0.6	0.72	0.79	0.69	0.78	0.96	0.66	0.51	0.52	0.91	0.56	0.74
	1	0.57	0.52	0.95	0.68	0.9	0.71
0.61	0.58	0.57	0.71	0.6	0.86	0.94	0.88	0.85	0.59	0.53	0.71	0.66
	0.66	0.88	0.69	0.92	0.81	0.98	0.81
0.97	0.9	0.66	0.67	0.72	0.57	0.94	0.69	0.97	0.65	0.59	0.58	0.87
	0.66	0.76	0.76	0.69	0.61	0.61	0.57
0.58	0.58	0.54	0.7	0.8	0.62	0.61	0.71	0.52	0.76	0.72	0.86	1
	0.56	0.78	0.86	0.79	0.99	0.81	0.71
0.79	0.6	0.57	0.98	0.8	0.62	0.85	0.57	0.51	0.73	0.85	0.78	0.85
	0.85	0.71	0.82	0.81	0.99	0.54	0.79
0.71	0.95	0.76	1	0.9	0.59	0.76	0.91	0.72	0.68	0.96	0.99	0.64
	0.98	0.84	0.88	0.67	0.65	0.88	0.56
0.93	0.77	0.59	0.79	0.92	0.92	0.78	0.76	0.89	0.63	0.91	0.52	0.55
	0.89	0.91	0.92	0.67	0.65	0.79	0.73
0.62	0.98	0.99	0.99	0.91	0.89	0.76	0.86	0.91	0.73	0.58	0.69	0.67
	0.72	0.54	0.77	0.92	0.58	0.69	0.5
0.96	0.76	0.74	0.67	0.69	0.93	0.81	0.59	0.89	0.74	0.57	0.56	0.83
	0.53	0.66	0.72	0.97	0.97	0.68	0.89
0.56	0.52	0.5	0.8	0.86	0.67	0.55	0.8	0.7	0.7	0.57	0.78	0.58
	0.99	0.52	0.62	0.7	0.78	0.65	0.97
0.98	0.96	0.68	0.99	0.89	0.85	0.58	0.99	0.67	0.82	0.94	0.86	0.99
	0.8	0.62	0.79	0.7	1	0.88	0.63
0.86	0.95	0.97	0.7	0.64	0.55	0.72	0.59	0.68	0.81	0.79	0.94	0.63
	0.73	0.97	0.6	0.58	0.56	0.97	0.72
0.52	0.89	0.58	0.64	0.68	0.81	0.67	0.67	0.81	0.9	0.53	0.68	0.57
	0.73	0.81	0.94	0.8	0.73	1	0.75
0.5	0.74	0.74	0.67	0.97	0.78	0.85	1	0.71	1	0.66	0.63	0.51
	0.86	0.8	0.94	0.75	0.55	0.89	0.6
0.66	0.73	0.73	0.75	0.87	0.74	0.76	0.67	0.9	0.82	0.69	0.94	0.99
	0.57	0.7	0.93	0.56	0.81	0.94	0.67
0.6	0.52	0.71	0.5	0.79	0.52	0.75	0.58	0.94	0.58	0.5	0.71	0.51
	0.62	0.79	0.59	0.87	0.88	0.97	0.71
0.66	0.87	0.73	0.78	0.73	0.96	0.9	0.8	0.62	0.84	0.88	0.6	0.52
	0.92	0.58	0.98	0.75	0.87	0.69	0.89
0.66	0.69	0.75	0.91	0.61	0.62	0.81	0.87	0.89	0.73	0.92	0.91	0.95
	0.74	0.71	0.88	0.85	0.53	0.86	0.56
0.73	0.53	0.59	0.73	0.52	0.91	0.51	0.63	0.72	0.66	0.53	0.56	0.52
	0.51	0.68	0.51	0.58	0.73	0.95	0.94
0.55	0.65	0.85	0.87	0.76	0.82	0.51	0.76	0.74	0.68	0.58	0.58	0.92
	0.53	0.79	0.8	0.77	0.58	0.77	0.81
0.87	0.56	0.7	0.83	0.94	0.7	0.83	0.81	0.91	0.84	0.71	0.61	0.98
	0.98	0.68	0.74	0.74	0.88	0.95	0.97
0.94	0.95	0.54	0.59	0.96	1	0.78	0.91	0.67	0.83	0.9	0.6	0.95
	0.63	0.95	0.77	0.67	0.51	0.86	0.68
0.83	0.89	0.99	0.88	0.54	0.94	0.59	0.62	0.6	0.53	0.72	0.52	1
	0.72	0.87	0.57	1	0.71	0.51	0.68
0.6	0.94	0.64	0.88	0.86	0.95	0.7	0.91	1	0.53	0.82	0.75	0.6
	0.73	0.77	0.94	0.56	0.53	0.55	0.88
0.5	0.97	0.94	0.69	0.68	0.73	0.94	0.76	0.64	0.66	0.84	0.66	0.76
	0.61	0.82	0.67	0.51	0.97	0.69	0.91
0.62	0.99	0.63	0.65	0.6	0.78	0.8	0.55	0.67	0.66	0.71	0.67	0.63
	0.89	0.86	0.98	0.6	0.67	0.87	0.68
```

0.8	0.64	0.64	0.57	0.65	0.99	0.52	0.75	0.92	0.88	0.58	0.6	0.79
	0.58	0.89	0.69	0.59	0.96	0.76	0.63					
0.76	0.95	1	0.57	0.6	0.93	0.56	0.72	0.66	0.75	0.5	0.5	0.91
	0.62	0.74	0.96	0.61	0.65	0.87	0.63					
0.77	0.9	0.87	0.87	0.54	0.93	0.61	0.76	0.7	0.86	0.9	0.95	0.74
	0.62	0.85	0.56	0.89	0.6	1	0.99					
0.61	0.7	0.9	0.76	0.69	0.87	0.63	0.71	0.68	0.98	0.52	0.92	0.62
	0.9	0.94	0.89	0.73	0.52	0.52	0.64					
0.75	0.54	0.86	0.77	0.61	0.96	0.71	0.69	0.72	0.9	0.51	0.87	0.75
	0.84	0.89	0.72	0.5	0.9	0.85	0.57					
0.6	0.79	0.67	0.6	0.79	0.65	0.81	0.75	0.53	0.68	0.76	0.86	0.89
	0.82	0.51	0.8	0.92	0.86	0.55	1					
0.6	0.93	0.96	0.86	0.9	0.61	0.89	0.76	0.72	0.78	0.8	0.62	0.72
	0.81	0.75	0.97	0.54	0.78	0.71	0.96					
0.75	0.73	0.84	0.81	0.94	0.75	0.59	0.89	0.58	0.71	0.76	0.99	0.85
	0.63	0.57	0.53	0.96	0.61	0.7	0.81					
0.8	0.93	0.55	0.61	0.57	0.85	0.69	0.93	0.95	0.98	0.83	0.66	0.94
	0.51	0.59	0.83	0.83	0.96	0.8	0.99					
0.71	0.79	0.97	0.64	0.61	0.62	0.52	0.77	0.89	0.55	0.57	0.65	0.77
	0.77	0.81	0.69	0.8	0.53	0.75	0.9					
0.58	0.52	0.92	0.6	0.74	0.53	0.51	0.77	0.6	0.77	0.53	0.86	0.74
	0.91	0.99	0.84	0.74	0.86	0.87	0.79					
0.52	0.57	0.99	0.78	0.63	0.83	0.82	0.74	0.76	0.78	0.98	0.78	0.6
	0.96	0.92	0.65	0.81	0.67	0.62	0.98					
0.78	0.53	0.73	0.67	0.91	0.59	0.64	0.95	0.61	0.71	0.56	0.51	0.52
	0.76	0.99	0.83	0.8	0.72	0.65	0.67					
0.88	0.62	0.75	0.69	0.6	0.89	0.69	0.82	0.6	0.6	0.74	0.5	0.53
	0.6	0.56	0.75	0.56	0.92	0.94	0.54					
0.93	0.56	0.61	0.51	0.93	0.78	0.66	0.74	0.83	0.65	0.76	0.71	0.86
	0.62	0.62	0.79	0.87	0.86	0.88	0.68					
0.98	0.67	0.83	0.89	0.81	0.97	0.52	0.72	0.99	0.91	0.99	0.59	0.58
	0.52	0.7	0.64	0.6	0.82	0.72	0.81					
0.78	0.52	0.81	0.81	0.74	0.68	0.87	0.92	0.9	0.96	0.89	0.73	0.63
	0.91	0.54	0.98	0.92	0.85	0.66	1					
0.98	0.69	0.56	0.64	0.79	0.98	0.59	0.95	0.72	0.99	0.61	0.73	0.58
	0.74	0.74	0.85	0.94	0.78	0.94	0.95					
0.59	0.69	0.54	0.54	0.7	0.89	0.64	0.74	0.79	0.62	0.73	0.89	0.84
	0.79	0.76	0.8	0.9	0.69	0.95	0.92					
0.54	0.67	0.58	0.94	0.67	0.86	0.59	0.78	0.64	0.68	0.94	0.79	0.97
	0.58	0.78	0.64	0.76	0.58	0.99	0.98					
0.53	0.62	0.93	0.6	0.68	0.68	0.98	0.86	0.63	0.54	0.78	0.97	0.8
	0.5	0.95	0.63	0.75	0.86	0.62	1					
0.81	0.88	0.9	0.61	0.89	0.95	0.74	0.62	0.82	0.6	0.89	0.73	0.52
	0.99	0.56	0.91	0.9	1	0.8	0.7					
0.99	0.77	0.76	0.58	0.79	0.87	0.94	0.65	0.97	0.75	0.79	0.89	0.51
	0.61	0.79	0.59	0.67	0.97	0.82	0.79					
0.77	0.72	0.5	0.74	0.55	0.92	0.85	0.89	0.69	0.58	0.77	0.97	0.73
	0.72	0.88	0.85	0.51	0.67	0.75	0.98					
0.51	0.76	0.87	0.79	0.84	0.9	0.61	0.5	0.88	0.72	0.77	0.81	0.78
	0.91	0.64	0.77	0.69	0.74	0.85	0.63					
0.92	0.8	0.55	0.72	0.68	0.73	0.7	0.62	0.55	0.82	0.85	0.58	0.95
	0.6	0.87	1	0.78	0.66	0.69	1					
0.52	0.81	0.89	0.66	0.94	0.9	0.67	0.77	0.71	0.57	0.62	0.68	0.82
	0.59	0.66	0.71	0.96	0.53	0.91	0.76					
0.66	0.51	0.89	0.68	0.64	0.75	0.79	0.61	0.9	0.63	0.73	0.51	0.55
	0.7	0.92	0.99	0.67	0.98	0.69	0.95					
0.97	0.89	0.56	0.88	0.53	0.6	0.99	0.96	0.69	0.82	0.69	0.89	0.67
	0.55	0.68	0.88	0.77	0.75	0.93	0.82					
0.62	0.89	0.72	0.5	0.82	0.77	0.5	0.89	0.56	0.94	0.54	0.78	0.57
	0.78	0.55	0.5	0.88	0.98	0.92	0.56					
0.63	0.99	0.96	0.71	0.52	0.61	0.57	0.94	0.59	0.96	0.56	0.68	0.84
	0.69	0.75	0.51	0.64	0.69	0.97	0.98					
0.68	0.96	0.68	0.93	0.58	0.55	0.94	0.98	0.69	0.71	0.65	0.63	0.56
	0.5	0.59	0.66	0.74	0.69	0.89	0.86					
0.92	0.93	0.78	0.87	0.98	0.59	0.75	0.61	0.88	0.76	0.9	0.69	0.93
	0.96	0.5	0.95	0.76	0.95	0.99	0.7					
0.79	0.77	0.65	0.74	0.59	0.52	0.75	0.75	0.99	0.54	0.77	0.54	0.68
	0.53	0.57	0.53	0.91	0.86	0.79	0.88					
0.52	0.74	0.53	0.88	0.67	0.53	0.84	0.58	0.52	0.78	0.65	0.84	0.89
	0.77	0.53	0.5	0.79	0.58	0.52	0.5					
0.93	0.91	0.92	0.91	0.63	0.63	0.95	0.74	0.83	0.5	0.76	0.97	0.75
	0.87	0.79	0.66	0.86	0.88	0.62	0.51					
0.79	0.94	0.78	0.65	0.73	0.83	0.69	0.52	0.57	0.9	0.89	0.95	0.8
	0.93	0.5	0.61	0.66	0.67	0.62	0.56					
0.79	0.97	0.67	0.8	0.73	0.62	0.8	0.73	0.73	0.65	0.99	0.56	0.57
	0.99	0.91	0.64	0.9	0.92	0.83	0.6					

```
0.65    0.53    0.65    0.59    0.8     0.8     0.68    0.51    0.99    0.65    0.61    0.71    0.63
        0.67    0.55    0.55    0.81    0.61    0.96    0.9
0.98    0.75    0.72    0.78    0.71    0.52    1       0.8     0.65    0.96    0.58    0.71    0.74
        0.9     0.53    0.71    0.73    0.78    0.76    0.8
0.9     0.92    0.85    0.71    0.8     0.69    0.9     0.99    0.88    0.9     0.9     0.84    0.68
        0.64    0.9     0.59    0.73    0.88    0.82    0.63
0.51    0.73    0.67    0.62    0.92    0.56    0.64    0.83    0.83    0.53    0.87    0.8     0.53
        0.55    0.84    0.88    0.84    0.85    0.62    0.84
0.78    0.99    0.67    0.51    0.86    0.61    0.92    0.79    0.53    0.85    0.84    0.5     0.87
        0.78    0.61    0.7     0.66    0.6     0.76    1
0.78    0.62    0.79    1       0.83    0.66    0.59    0.71    1       0.64    0.68    0.94    0.93
        0.94    0.92    0.5     0.99    0.92    0.58    0.65
1       0.56    0.83    0.87    0.99    0.58    0.53    1       0.67    0.51    0.61    0.53    0.73
        0.52    0.73    0.51    0.84    0.64    0.74    0.63
0.71    0.6     1       0.51    0.88    0.99    0.74    0.58    0.85    0.7     0.75    0.82    0.89
        0.62    0.69    0.66    0.92    0.65    0.6     0.56
0.6     0.75    0.89    0.77    0.73    0.77    0.77    0.99    0.83    0.79    0.51    0.66    0.86
        0.96    0.8     1       0.95    0.84    0.94    0.68
0.6     0.93    0.63    0.69    0.78    0.89    0.92    0.86    0.84    0.92    0.59    0.76    0.65
        1       0.6     0.89    0.67    0.75    0.6     0.57
0.69    0.6     0.94    0.5     0.92    0.75    0.69    0.96    0.67    0.83    0.59    0.87    0.87
        0.72    0.71    0.64    0.99    0.5     0.97    0.71
0.53    0.7     0.55    0.72    0.52    0.92    0.92    0.52    0.75    0.99    0.62    0.72    0.85
        0.57    0.8     0.7     0.81    0.78    0.8     0.82
0.56    0.7     0.58    0.7     0.65    0.6     0.88    0.54    1       0.66    0.92    0.95    0.54
        0.96    0.83    0.67    0.7     0.95    0.76    0.94
0.77    0.97    0.71    0.98    0.72    0.85    0.57    0.96    0.81    0.51    0.8     0.75    0.91
        0.92    0.61    0.52    0.73    0.71    0.75    0.89
0.89    0.56    0.71    0.81    0.52    0.81    0.73    0.69    0.52    0.61    0.78    0.67    0.79
        0.7     0.83    0.95    0.92    0.52    0.62    0.91
0.66    0.83    0.71    0.96    0.5     0.96    0.63    0.76    0.9     0.88    0.68    0.56    0.6
        0.88    0.86    0.92    0.74    0.82    0.84    0.7
0.76    0.89    0.89    0.73    0.66    0.79    0.94    0.89    0.72    0.81    0.8     0.88    0.73
        0.97    1       0.58    0.5     0.79    0.77    0.58
0.62    0.71    0.6     0.7     0.72    0.56    0.55    0.94    0.7     0.97    0.84    0.77    0.85
        0.58    0.6     0.52    0.91    0.55    0.68    0.86
0.66    0.94    1       0.69    0.59    0.87    0.54    0.68    0.78    0.66    0.72    0.63    0.94
        1       0.73    0.98    0.99    0.77    0.64    0.77
0.89    0.87    0.72    0.9     0.59    0.7     0.55    0.81    0.89    0.62    0.56    0.65    0.63
        0.7     0.75    0.73    0.85    0.51    0.62    0.57
0.75    0.53    0.75    0.89    0.86    0.75    0.77    0.86    0.67    0.81    0.82    0.93    0.83
        0.79    0.68    0.9     0.9     0.94    0.88    0.77
0.55    0.55    0.71    0.56    0.85    0.93    0.57    0.77    0.96    0.8     0.55    0.8     0.87
        0.62    0.64    0.58    0.91    0.96    0.58    0.72
0.91    0.92    0.52    0.6     0.63    0.5     0.77    0.76    0.93    0.68    1       0.68    0.94
        0.96    0.99    0.51    0.79    0.69    0.8     1
0.5     0.66    0.88    0.57    0.58    0.77    0.7     0.75    0.57    0.93    0.89    1       0.69
        0.61    0.94    0.61    0.51    0.57    0.79    0.66
0.53    0.95    0.99    0.62    0.69    0.55    0.73    0.59    0.87    0.82    0.79    0.94    0.73
        0.83    0.95    0.57    0.93    0.99    0.57    0.69
0.81    0.97    0.64    0.55    0.52    0.61    0.65    0.58    0.85    0.88    0.84    0.89    0.97
        0.62    0.57    0.66    0.71    0.88    0.64    0.55
0.88    0.95    0.7     0.51    0.98    0.55    0.68    0.69    0.5     0.66    0.55    0.64    0.87
        0.64    0.98    0.56    0.85    0.58    0.5     0.63
0.76    0.98    0.65    0.94    0.93    0.74    0.66    0.7     0.97    0.99    0.94    0.5     0.9
        0.81    0.57    0.84    0.62    0.64    0.57    0.57
0.57    0.84    0.97    0.76    0.87    0.61    0.77    0.78    0.75    0.74    0.7     0.74    0.88
        0.59    0.87    0.64    0.91    0.96    0.88    1
CC
CC initial brine salinity
*---- C50 C60
0.2 0
CC
CC*****************************************************************
CC                                                                *
CC PHYSICAL PROPERTY DATA                                         *
CC                                                                *
CC*****************************************************************
CC
CC
CC OIL CONC. AT PLAIT POINT FOR TYPE II(+)AND TYPE II(-), CMC
*---- c2plc c2prc epsme ihand
0     1   0.0001  0
CC
CC flag indicating type of phase behaviour parameters
*---- ifghbn
0
```

```
CC alcohol 1 data (slope etc.)
CC
*---- hbns70 hbnc70 hbns71 hbnc71 hbns72 hbnc72
0.131 0.1   0.191  0.026  0.363  0.028
CC alcohol 2 data (slope etc.)
CC
*---- hbns80 hbnc80 hbns81 hbnc81 hbns82 hbnc82
0      0      0      0      0      0
CC
CC min and max salinities for both alcohols
*----CSEL7 CSEU7 CSEL8 CSEU8
0.177 0.344 0 0
CC
CC cse for Ca and Alcohol 1&2
*----BETA6 BETA7 BETA8
0. -2. 0.
CC
CC alcohol partition coefficient
*----IALC OPSK7O OPSK7S OPSK8O OPSK8S
1 0. 0. 0. 0.
CC
CC no. of iterations and tolerance
*----NALMAX EPSALC
0     0
CC
CC for ialc=1 alcohol 1 part. Coefficient
*----AKWC7 AKWS7 AKM7 AK7 PT7
4.671 1.79 48. 35.31 .222
CC
CC for ialc=1 alcohol 2 part. Coefficient
*----AKWC8 AKWS8 AKM8 AK8 PT8
0.     0.   0.   0. 0.
CC
CC IFT MODEL FLAG
*--- IFT
0
CC
CC INTERFACIAL TENSION PARAMETERS
*----G11 G12 G13 G21 G22 G23
13 -14.8 0.007 13 -14.5 0.010
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
*---- xiftw
1.3
CC
CC ORGANIC MASS TRANSFER FLAG
*---- imass icor
0   0
CC
CC
*----IWALT ICOR
0 0
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
*---- itrap t11 t22 t33
0     1865  59074  364.2
CC
CC Relative Permeability Type (0= Imbibition Corey)
*----IPERM IRTYPE
0     0
CC
CC Relative Permeability parameters
*---- ISRW IPRW IEW
0    0    0
CC
CC Residual Saturations at low capillary number
*----S1RWC S2RWC S3WRC
0.1   0.4   0
CC
CC Endpoint relative permeability at low capillary number
*----P1RW P2RW P3RW
1   1  1
CC
CC CONSTANT REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT LOW CAPILLARY NO.
*---- e1wc e2wc e3wc
1    1    1
CC
```

```
CC WATER AND OIL VISCOSITY, RESERVOIR TEMPERATURE
*---- VIS1 VIS2 TSTAND
0.8 1.74 0
CC
CC Microemulsion viscosity data
*----ALPHAV1 V2 V3 V4 V5
0      0  0  0  0
CC
CC Polymer Property Data
*----AP1 AP2 AP3
0   0   0
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*----BETAP CSE1 SSLOPE
1   0.01  0.175
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*----GAMMAC GAMHF POWN  IPMOD ISHEAR RWEFF GAMHF2
0      13  1.645   0     0     0.25  -15.04
CC
CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*----IPOLYM EPHI3 EPHI4 BRK CRK RKCUT
0      0      0    0   0   10
CC
CC Pressure gradient of water/oil/
*----DEN1 DEN2 DEN23 DEN3 DEN7 DEN8 IDEN
0.4375 0.34 0.3491 0 0 0 0
CC
CC Flowrate units (cft/D)
*----ISTB
0
CC
CC Fluid Compressibilities
*----Brine Oil Surf Alc1 Alc2
0.000003 0 0 0 0
CC
CC Capillary pressure data
*----ICPC IEPC IOW
0    0    0
CC
CC Capillary Pressure Parameter
*----CPC
0
CC
CC Capillary Pressure Parameter
*----EPC
0
CC
CC Molecular Diffusion Coefficient (ft2/day) in phase 1 (water)
*----D(KC= 1-9)
0 0 0 0 0 0 0 0 0.005 0.005 0.005 0.005 5.1
CC
CC Molecular Diffusion Coefficient (ft2/day) in phase 2 (oil)
*----D(KC= 1-9)
0 0 0 0 0 0 0 0 0 0 0 0 0
CC
CC Molecular Diffusion Coefficient (ft2/day) in phase 3 (microemulsions)
*----D(KC= 1-9)
0 0 0 0 0 0 0 0 0 0 0 0 0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----ALPHAL(1) ALPHAT(1)
0.5 0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----ALPHAL(2) ALPHAT(2)
0.5 0.0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----ALPHAL(3) ALPHAT(3)
0.5 0.0
CC
CC flag to specify organic adsorption calculation
*---- iadso
0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
```

```
*---- AD31 AD32 B3D AD41 AD42 B4D IADK IADS1 FADS REFK
1 0.5 1000 0 0 100 0 0 0 0
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*---- QV XKC XKS EQW
0 0.25 0.2 419
CC
CC TRACER PARTITIONING COEFFICIENT
*---- TK(I),I=1,NTW + NTA
0.0 0.5 1 1.5 2
CC
CC Part Coef as a function of salinity
*---- TKS(I) C5INI
0 0 0 0 0 0
CC
CC Radioactive Decay Coefficient
*---- RDC(I),I=1,NTW + NTA
0.0 0.0 0.0 0.0 0.0
CC
CC Tracer Adsorption Parameter
*----RET(I), I=1,NTW + NTA
0.0 0.0 0.0 0.0 0.0
CC
CC*******************************************************************
CC                                                                  *
CC WELL DATA                                                        *
CC                                                                  *
CC*******************************************************************
CC
CC
CC Flag about constant boundary zones
*---- IBOUND IZONE
0      0
CC
CC
*----NWELL IRO ITSTEO NWREL
2     2    0     2
CC
CC Well location and data
*----IDW IW JW IFLAG RW SWELL IDIR IFIRST ILAST IPRF
1   1  1  4  0.3333 0     3    1      1     0
CC
CC Well name
*----WELNAM
PROD1
CC
CC
*----ICHEK PWFMIN PWFMAX QTMIN QTMAX
1    3500   10000  0    -10000
CC
CC Well location and data
*----IDW IW JW IFLAG RW SWELL IDIR IFIRST ILAST IPRF
2  100 20 1  0.3333 0    3    1      1     0
CC
CC Well name
*----WELNAM
INJ1
CC
CC
*----ICHEK PWFMIN PWFMAX QTMIN QTMAX
1    0     10000   0    10000
CC
CC Production Rate
*----ID(M) QI(M,1)
1     -8590.3
CC
CC Injection Rate (per component)
*----ID(M) QI(DM) C(M,KC,L)
2    8590.3   1 0 0 0 0 0 0 0 1 1 1 1 1
2     0       0 0 0 0 0 0 0 0 0 0 0 0 0
2     0       0 0 0 0 0 0 0 0 0 0 0 0 0
CC
CC
**----TINJ CUMPR1 CUMHI1 WRHPV WRPRF RSTC
1   0.1     0.1    0.1   0.1   0.5
CC
CC FOR IMES=4 ,THE INI. TIME STEP,CONC. TOLERANCE,MIN. AND MAX. Time step size
```

```
*----DT          DCLIM    CNMAX     CNMIN
0.1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0.05
CC
CC
*----IBMOD
0
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*---- IRO ITIME IFLAG
2 0 4 1
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*---- NWEL1
0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*---- NWEL2 ID
1 2
CC
CC
*----ID(M) QI(DM) C(M,KC,L)
2     8590.3  1 0 0 0 0 0 0 0 0 0 0 0 0
2     0       0 0 0 0 0 0 0 0 0 0 0 0 0
2     0       0 0 0 0 0 0 0 0 0 0 0 0 0
CC
CC
*----TINJ CUMPR1 CUMHI1 WRHPV WRPRF RSTC
3000   1     1      1     1    1
CC
CC FOR IMES=4 ,THE INI. TIME STEP,CONC. TOLERANCE,MIN. AND MAX. Time step size
*----DT          DCLIM    CNMAX     CNMIN
3 0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.1 0.1 3 0.5
```

-- Corresponding HEAD file

```
RUN001
NX  NY  NZ  N  NWELL
100 20   1   13   2
NTW  NTA
5    0
NO   NPHAS
0     3
NSUB  MSUB
0      0
```