

NEW LABORATORY DATA BASED MODELING OF MISCIBLE DISPLACEMENT IN COMPOSITIONAL SIMULATION

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ABSTRACT

This paper discusses a new approach that relates primarily to the laboratory and modeling studies that precede the Equation of State (EOS) based compositional simulation of miscible displacement.

Multi-phase flow through porous media is governed by the interaction between capillary, viscous and gravitational forces. The flow regime can be characterized by the capillary number, N_c and the Bond number, N_b , which are defined as dimensionless measures for the ratio of - viscous and capillary - and - gravitational and capillary - forces at the pore scale.

The importance of these factors in designing an accurate EOS characterization and phase behavior of the reservoir fluids coupled with the flow through porous media considerations to obtain an accurate description of PVT and reservoir rock data for use in compositional simulation will be reviewed.

The determination of miscibility conditions by advanced reservoir fluid studies is discussed along with a special core flood experiment design for measuring the interfacial tension dependent relative permeabilities.

In the commercial EOS based compositional simulation software packages, the conventional belief is that using an ideal relative permeability curve to correspond to total miscibility and scaling these curves for given conditions is satisfactory. Also assumed is that the impact of the errors introduced on recoveries is minimal. These assumptions might hold true for homogeneous media and ideal miscibility conditions only.

For a dynamic description of flow regions during miscible displacement process, a new laboratory data based model of interfacial tension dependent of relative permeability and capillary pressure data is presented. Also presented are the advantages of incorporation of this model in the commercial EOS based compositional simulation software packages.

INTRODUCTION

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

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

where E = overall displacement efficiency, E_D = microscopic displacement efficiency, and E_V = macroscopic displacement efficiency.

Microscopic displacement relates to the displacement or mobilization of oil at the pore scale. Macroscopic displacement efficiency relates to the effectiveness of the displacing fluid(s) in contacting the reservoir in a volumetric sense. It is desirable in an *EOR* process that the values of E_D and E_V and consequently E , approach 1. An idealized *EOR* process would be one in which the displacing fluid removed all oil from the pores contacted by the fluid ($S_{or} \rightarrow 0$).

In enhanced recovery operations, oil entrapment occurs due to complex interactions between viscous, gravity and capillary forces. Enhancing recovery from fields typically involves altering the relative importance of the viscous and capillary forces. The capillary number and Bond number, which are dimensionless measures for the ratio of - viscous and capillary - and - gravitational and capillary - forces at the pore scale, respectively, provides the basic expression of the relative importance of these forces and are commonly defined as

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

$$N_b = \frac{kg\Delta\rho}{\sigma} \quad (3)$$

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

PVT AND PHASE BEHAVIOR EXPERIMENTAL DESIGN

The value of the core flood study depends on the quality of the fluid samples obtained. Three common methods are used to sample the reservoir fluid: (i) Bottomhole sampling, (ii) Wellhead sampling, and (iii) Separator sampling.

The appropriate PVT experiments are related closely to the processes implemented in the field. The overall purpose of reservoir fluid studies is to provide basic volumetric, phase and viscosity data of reservoir fluids.

The thermodynamic conditions required for dynamic miscibility with injection gas, as well as the gas composition are best determined by miscibility studies. The swelling (P - x) test is the most common PVT experiment for first-contact miscibility studies, which provides information on the gas injection fluid behavior as function of pressure at reservoir temperature. The Rising Bubble Apparatus (RBA) experiment is a rapid and accurate technique to provide qualitatively approximate first contact and multiple-contact minimum miscibility pressures (MMP) for oil - injection gas mixtures. The MMP determined by slim tube experiments has been accepted by the oil industry as the target reservoir pressure for designing a miscible process. However, slim tubes have a “porous medium” which bears little resemblance to reservoir rocks and water is not present during the test. Multiple contact experiments are performed to generate quasi-statically the complete range of compositions and interfacial tensions that will be generated dynamically in the reservoir under injection conditions. The multiple contact tests are normally performed at the MMP determined from RBA, slim tube tests or at reservoir pressure. For a better understanding of phase behavior and miscibility conditions, multiple contacts at different pressures are recommended. The most common experiments conducted to determine the miscibility conditions are shown schematically in Figure 2.

In addition to the experiments described above, special swelling (P - x) tests with solvent/fluid generated from the multiple contact experiments are recommended. These are performed to investigate the interaction gas-oil on the leading edge of the displacement and near the injection zone. These interactions are illustrated in Figure 3 and 4.

CORE FLOOD DISPLACEMENT EXPERIMENTAL DESIGN

Routine core analysis (RCAL) and special core analysis (SCAL) are the main sources of data to guide the reservoir engineer in assessing the reservoir performance.

Special core analysis attempts to extend the data provided by routine measurements to situations more representative of reservoir conditions. Tests are carried out to measure fluid distribution, electrical properties and fluid flow characteristics in the two and occasionally three phase situation, and are made on preserved core. A schematic diagram of common SCAL measurements is given in Figure 5.

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

In this paper, a new method for the relative permeability measurements, which couples fluid phase behavior, fluid-rock interaction and fluid flow in case of miscible displacements, was developed. This methodology provides key input data for compositional reservoir simulation models, which will be discussed more in details.

For this purpose, the equilibrium high and low interfacial tension fluid pairs, which are the end products of the multiple contact miscibility studies, are used as the baseline fluids to conduct these special relative permeability experiments. Since the fluids are the equilibrium condition, no mass transfer will occur between the gas and oil phase, making them ideal displacement fluids for relative permeability experiments at reservoir conditions.

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

Effects of Wettability and Pore Size Distribution

Wettability and pore size distribution may significantly impact recovery performance. In water-wet porous media, the water phase will occupy the smallest pores, while the oil and gas phase occupies the large pore spaces. In oil-wet porous media, neither the water phase nor the gas phase wets the pore surfaces and thus the water and gas phases compete for the largest pores.

An example of this situation is shown in Figure 6 (Case A) where the rock exhibits a wide pore size distribution and a large fraction of the oil in place is trapped and contained in a relatively small pore space with small pore throat radii. This most commonly would occur in an oil wet situation where low initial water saturation is present and the large portion of the pore space is saturated with liquid hydrocarbons. Since the pore throats are a direct function in the capillary pressure which, in turn, is a function of the interfacial tension between the phases, in order to effectively access and sweep a large portion of the

reservoir volume encompassed by the small pore system, we must generate a very low interfacial tension.

With the same pore size distribution Figure 6 (Case B), but in a strongly water-wet situation, a large portion of the micro-porosity is saturated with water rather than oil and represents pore space that is not necessary to penetrate in order to achieve significant recovery of the oil. In this example, one can observe that a much higher interfacial tension condition could be used to obtain a comparable overall recovery factor to the oil wet situation.

Another situation is, where a skewed pore size distribution is present and a large portion of the recoverable oil is contained in macropores with very little micro-porosity Figure 6 (Case C). Once again, one can observe that a relatively high interfacial tension can result in effective recovery of a large portion of the oil in-place in the reservoir. Other factors which may adversely influence recovery in such a case would be viscosity and mobility ratio as well as gravity override effects, since reservoirs with these types of size distributions are often characterized by large interconnected vugs or fractures or other macroporous features which may create high permeability contrasts and result in low overall displacement efficiency.

Figure 7 illustrates typical results from an experimental suite of these types, using two pairs of fluids with maximum and minimum interfacial tension. Relative permeability curves in Figure 7 (Case 1) represent the results of an experimental program where interfacial tension effects dominate and are significant in increasing the recovery of oil. It can be seen from this set of incremental relative permeability curves that the reduction in interfacial tension between the two fluid sets causes a significantly lower residual oil saturation to be obtained and much higher overall recovery factor and better sweep efficiency.

Contrasting this effect, relative permeability curves in Figure 7 (Case 2) provide an illustration of a reservoir scenario where the mobility, pore size distribution, and core wettability effects appear to completely dominate. Examination of the relative permeability curves from this test using the same pairs of fluids as in Case 1 illustrates that there was virtually no difference in relative permeability performance and, in particular, the ultimate recovery of residual oil saturation.

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

These factors clearly illustrate the importance of an accurate characterization of the reservoir fluids and coupling the phase behavior and interfacial tension conditions with

the flow in porous media considerations to obtain an accurate description of PVT and reservoir rock data for use in compositional simulation.

PVT AND CORE DATA IN COMPOSITIONAL SIMULATION

Most of the commercially available EOS compositional simulators and in-house models have been improved significantly in terms of robustness, efficiency, and features. As computer power increases, the use of EOS compositional simulators to model enhanced oil recovery processes should be expected to increase in the future. In principle, compositional simulation should be used whenever the compositional effects are important.

Compositional reservoir simulators are built on the basis of mass or molar balances equations of each component [2]. The water equation is unchanged from the black-oil formulation

$$\nabla \cdot \left(\frac{\lambda_w}{B_w} \nabla \Phi_w \right) + q_w = \frac{\partial}{\partial t} \left(\frac{\phi S_w}{B_w} \right) \quad (4)$$

The hydrocarbon equation accounts for flow of component i in both the oil and gas phases:

$$\nabla \cdot \left(x_i \xi_o \lambda_o \nabla \Phi_o + y_i \xi_g \lambda_g \nabla \Phi_g \right) + q_i = \frac{\partial}{\partial t} \left[\phi \left(x_i \xi_o S_o + y_i \xi_g S_g \right) \right] \quad (5)$$

In the above equations, λ_p - phase mobility = kk_{rp}/μ_p ($p = o, g, \text{ or } w$), Φ_p - phase potential, ($p = o, g, \text{ or } w$), S_p - phase saturation ($p = o, g, \text{ or } w$), ξ_p - molar phase density ($p = o, g, \text{ or } w$), x_i - mole fraction of component i in liquid phase, y_i - mole fraction of component i in gas phase, q_i - injection or production rate of component i , q_w - injection or production rate of component water, B_w - water formation volume factor, ϕ - porosity.

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

EOS Characterization and Modeling

The main objective of EOS modeling is an accurate prediction of fluid behavior in the entire P - V - μ - x envelope at reservoir temperature. PVT laboratory measurements are made on only a small portion of the composition path encountered throughout the displacement, whereas an EOS can be used to predict behavior for the entire composition path and pressure range of the process.

The accuracy of any EOS model depends on the quality of the laboratory PVT data and procedures used to obtain the EOS parameters. For best results a data set exhibiting both volatility and extraction data is required [3]. Generally the results of an EOS model must be tuned by nonlinear regression of one or more variables to match experimental data. To validate the EOS model, as described above, laboratory slim tube experiments can be evaluated using a compositional simulator.

Reservoir Rock Properties

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

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

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

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

To better describe the reservoir performance, the authors propose [4] that two sets of boundary capillary pressure and relative permeability curves measured from multi-contacted fluid pairs as describe above, if incorporated in the compositional simulator will substantially improve the predicting capabilities. Generally, the miscible

displacement will lie within these boundaries and representative values of capillary pressure and relative permeability curves at given pressure and composition can be determined from interfacial tension using the following relationships:

Saturation:

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

Relative permeability to gas and oil phase:

$$krg = \sigma^* krg|_{\sigma_{max}} + (1 - \sigma^*) krg|_{\sigma_{min}} \quad (7)$$

$$krog = \sigma^* krog|_{\sigma_{max}} + (1 - \sigma^*) krog|_{\sigma_{min}} \quad (8)$$

Capillary pressure:

$$Pc = \sigma^* Pc|_{\sigma_{max}} + (1 - \sigma^*) Pc|_{\sigma_{min}} \quad (9)$$

$$\text{where } \sigma^* = \frac{\sigma - \sigma_{min}}{\sigma_{max} - \sigma_{min}} \quad (10)$$

is the dimensionless interfacial tension used to scale the measured bounding values. The interfacial tension, σ is obtained using the modified Macleod-Sugden correlation for multi-component mixtures, given by Weinaug and Katz as

$$\sigma = \left[\sum_i P_i \left(x_i \frac{\rho_o}{M_o} - y_i \frac{\rho_g}{M_g} \right) \right]^\theta \quad (11)$$

where σ is in (dynes/cm) and ρ is the phase density in g/cm^3 , M is the phase molecular weight, x_i is mole fraction of component i in liquid, y_i is mole fraction of component i in gas, and P_i is the parachor of component i which can be calculated by using correlations. The exponent θ has a value slightly below 4, which was originally proposed by Macleod and Sugden [5].

Since relative permeability curves are determined with respect to the equilibrium fluid, for both the maximum and minimum interfacial tension conditions, that can exist in the displacement, these relative permeability curves can be input into the simulator model as the bounding relative permeability curves. An algorithm, coupled with an equation of state used in the model to adjust the shape of the relative permeability and capillary pressure curves as interfacial tension changes in the reservoir, as described in Equations 6 through 11, needs to be introduced in Equation 5 to accordingly reflect changes in capillary number. Using a tuning protocol of this type allows for more accurate evaluation and calibration of the compositional reservoir simulation model to predict actual reservoir performance.

CONCLUSIONS

1. A novel method of incorporating relative permeability data to a compositional simulator in case of miscible and near-miscible displacement during gas injection conditions was presented.
2. This method has been applied to several laboratory scale measurements in various porous media with heterogeneous pore size distribution and permeability realizations, coupled with miscibility development.
3. In compositional simulation techniques, for every rock region there is one set of saturation functions. With these modifications, the simulator has dynamic saturation functions per rock region and allocates appropriate relative permeability curves based on measured laboratory data.
4. The technique proposed can also be used in gas condensates reservoirs to measure the relative permeabilities to equilibrium fluids below the saturation pressure in the reservoir and near the wellbore.

NOMENCLATURE

k_{rg} = Gas phase relative permeability

k_{rog} = Oil phase relative permeability

P_c = Capillary pressure

S_{or} = Residual oil saturation

u = Darcy's velocity

ρ = Phase density

μ = Phase viscosity

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Figure 1. Residual Oil Saturation vs. Capillary Number

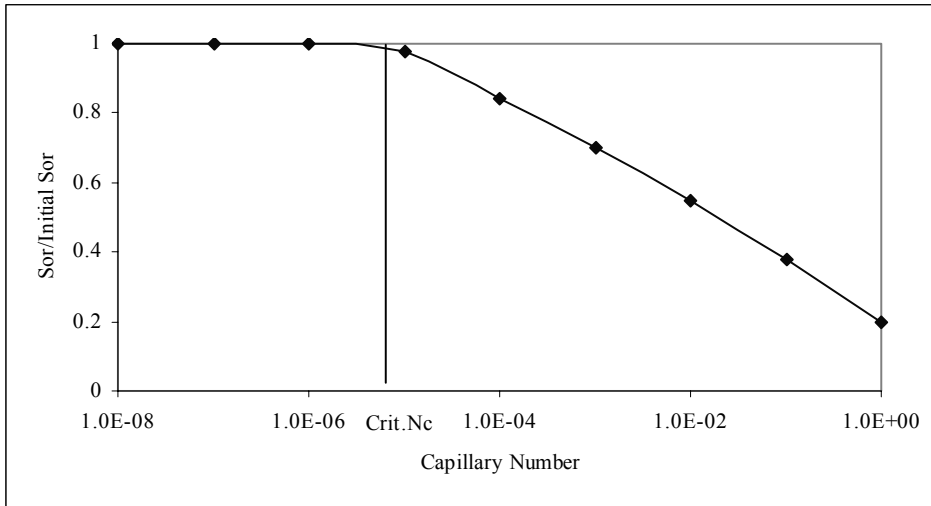


Figure 2. Miscibility Study – Laboratory Protocol

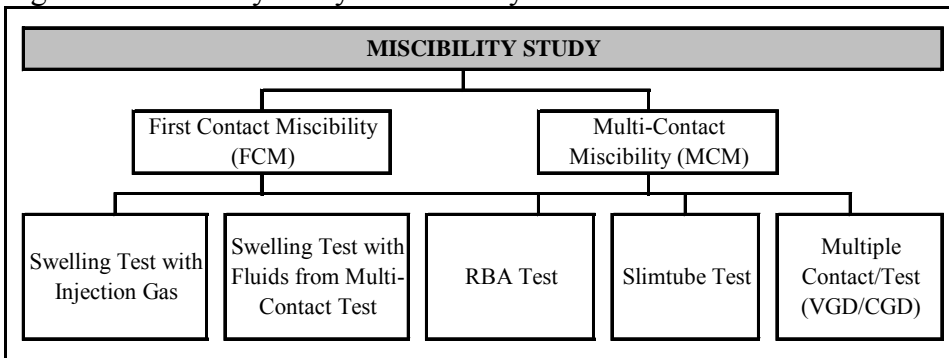


Figure 3. Swelling Test (P-x) – Reservoir Fluid-Lean Gas

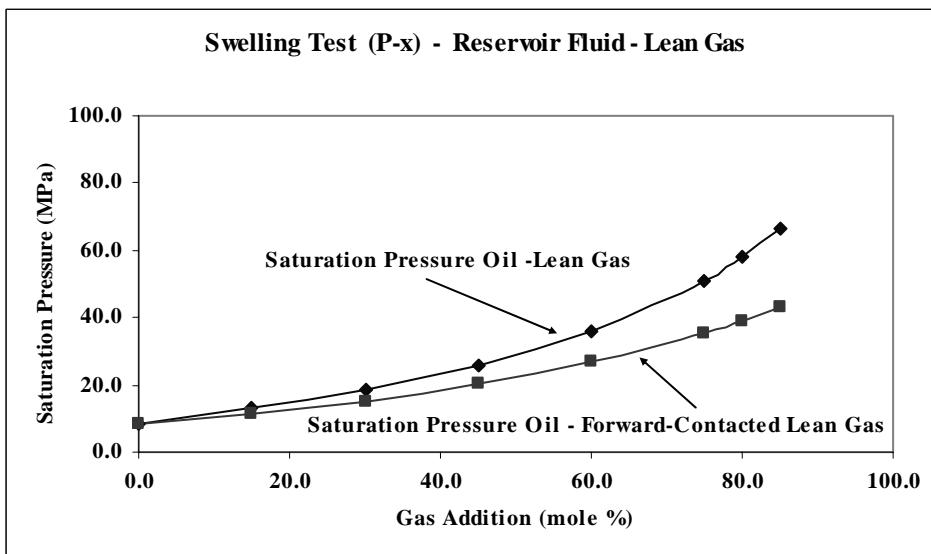


Figure 4. Swelling Test (P-x) – Reservoir Fluid-Enriched Gas

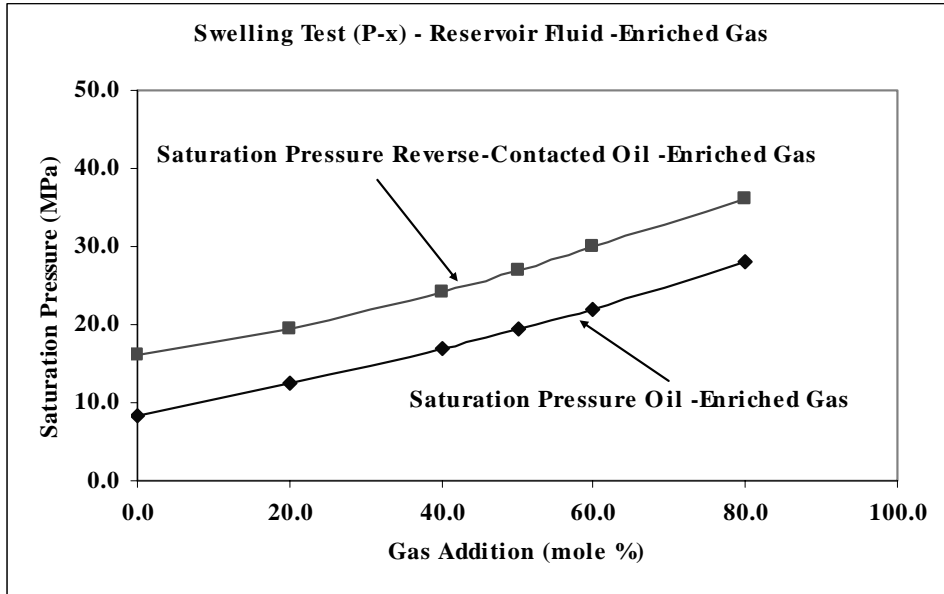


Figure 5. Special Core Analysis

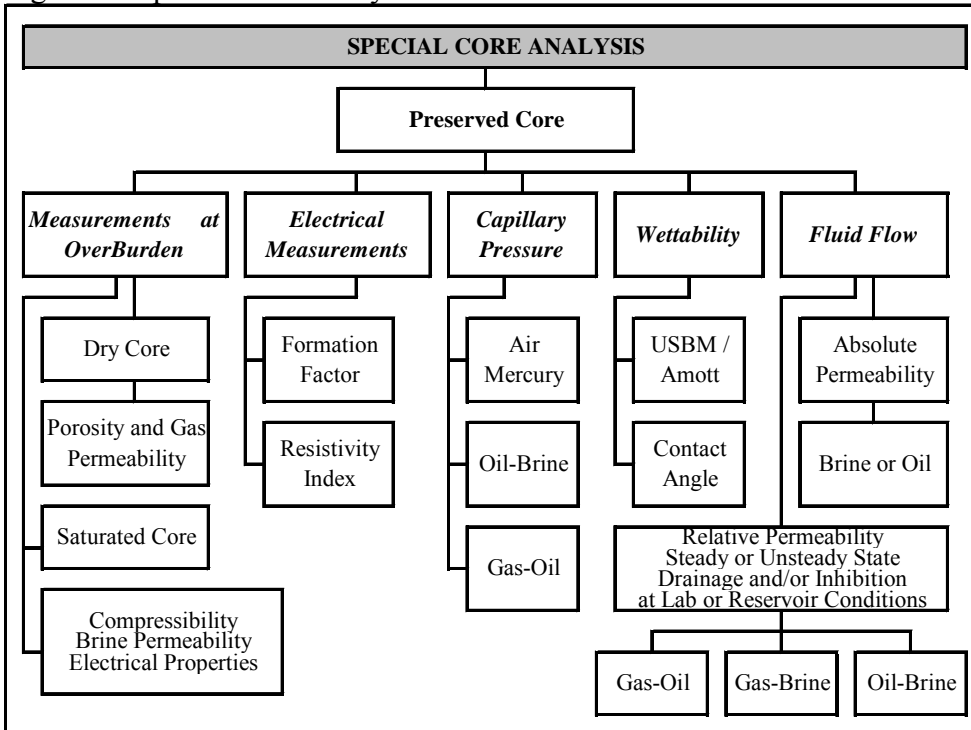
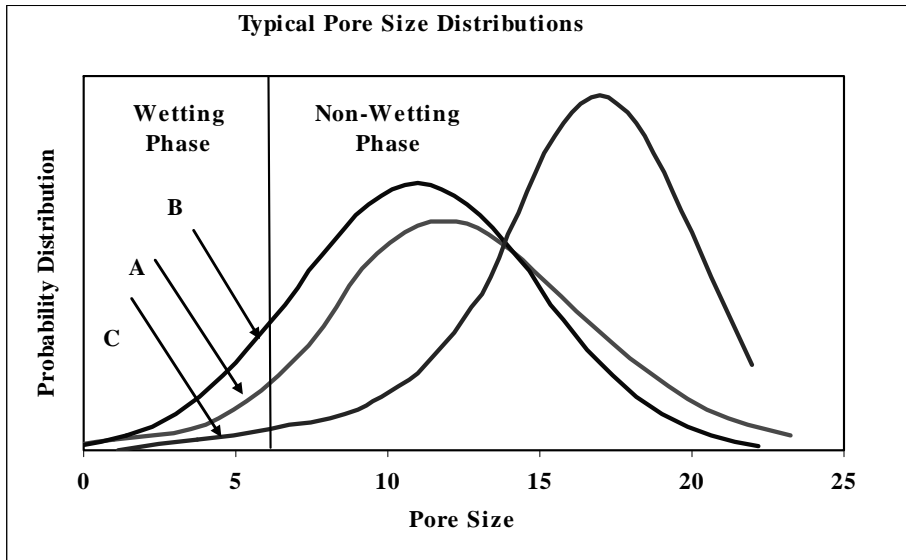
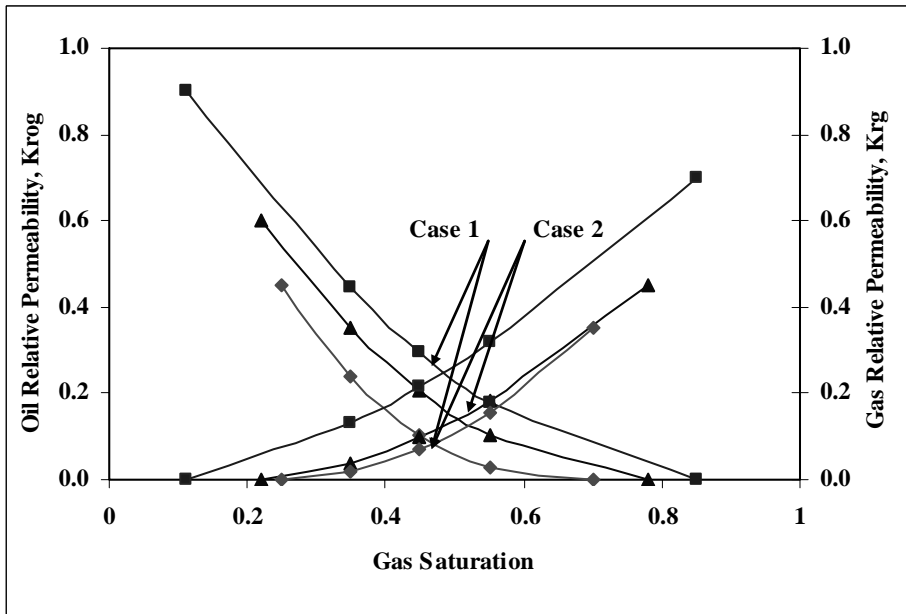


Figure 6. Typical Pore Size Distributions



(Case A – Oil-wet situation, Case B- Water-wet situation, Case C – Water-wet skewed pore size distribution)

Figure 7. Relative Permeabilities at Constant Interfacial Tension



Case 1 – Relative permeabilities to minimum and maximum interfacial tension pairs of fluids in case of interfacial tension effects dominated performance.

Case 2 – Relative permeabilities to minimum and maximum interfacial tension pairs of fluids in case of mobility, pore size distribution, and wettability effects dominated performance.