CORE BASED PERSPECTIVE ON UNCERTAINTY IN RELATIVE PERMEABILITY

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ABSTRACT

Core analysts are increasingly required to provide uncertainty ranges in parameters (P10/50/90) for use in reservoir simulation. This is particularly difficult for relative permeability as the numbers of samples are very limited, there are significant time pressures, and there are many unexplored issues. We have developed a simple framework to address these issues, and the purpose of this paper is to share our initial efforts. We will use examples to discuss the sources of uncertainty (geological, process, subjective) and their impact, and our attempts to quantify them.

INTRODUCTION

Relative permeability data can be an important input to reservoir simulation studies. However, due to uncertainties in laboratory measurements, sampling paucity and differences in scale, there is lack of agreement as to the need to honor laboratory measurements. Williams, Keating, and Barhoughty [1] state "although some are opposed to modifying laboratory-relative permeability curves, the field data may strongly suggest that conformance and displacement efficiencies are poorer than laboratory estimates. This requires that changes be made." In order to match the water cut without affecting the pressure match, they propose that the most effective method is to alter the relative permeability curves. For sandstones, Williams et. al. [1] note that they typically lowered laboratory K_{rw} curves and increased laboratory S_{orw} values.

Given this backdrop, the application of laboratory relative permeability data in Chevron's reservoir simulation studies has been uneven. Where fields have significant history, some have found it convenient to begin with a single relative permeability curve in the up-scaled models, as global adjustments are easier to obtain a history match. This single curve is typically created from averaging end-points, averaging the normalized raw data, and then creating a single de-normalized curve. Others have created several rock regions, and tried to honor the laboratory data as much as possible. The issue becomes acute in new projects that do not have significant history. Many new projects are also being fast tracked, and it is very difficult to obtain high quality, well sampled laboratory measurements before simulation studies need to be completed. The prediction methodology in these cases is very uneven.

Chevron [2] and others have been using Experimental Design (ED) techniques to quantify uncertainty in recovery predictions. In this technique, parameters are varied simultaneously instead of the prior relatively inefficient one-parameter at a time variation. Relative permeability is typically parameterized using curve shapes and end-points, and the engineer is required to input P10-50-90 estimates of these parameters. Typically, the P10 curve represents the scenario that there is less than a 10% chance that the oil recovery will be worse; P50 is 50%, and P90 is 90%.

Corbett, Potter, and Bowen [3] have presented guidelines for a sampling strategy using an experimental design checklist approach. The essential milestones of this strategy are – consult, clarify objectives, summarize beliefs and uncertainties, broad strategy, conduct experiments, results, and consult. Mohammed and Corbett [4] have addressed the issue of the number of relatively permeability measurements needed using an approach based on geological analysis, rock typing, heterogeneity analysis, and flow simulation. Our approach is strategically aligned with the approaches presented in [3] and [4], though the tactics are different. This is driven by our historical context and project requirements.

SOURCES OF UNCERTAINTY

We have classified the uncertainty in relative permeability data in three main categories –

1. Geological uncertainty -- typically use a simple, standard test to gauge variability by rock type. If relative permeability is assigned by rock type, instead of one generic parameter, this uncertainty can be reduced. This is predicated on a very good and extensive sampling program.
2. Process uncertainty -- probe different effects (rate, wettability, reservoir condition tests...). It also includes effects of upscaling -- something core analysts do not often do, but leave to the reservoir engineers.
3. Subjective Uncertainty -- this is uncertainty due to inexperience, introduction of analog data, and is hard to quantify.

1. Geological Uncertainty

The typical process we follow is –

(i) Sample selection is always done in conjunction with a geologist, formation evaluation specialist, and reservoir simulation engineer. Many samples are selected at this stage, as the focus is on capturing the variability in the reservoir. Depending on the timing of the SCAL project, this may be done --
   a. without access to any routine core data
   b. using k-ϕ, geological description, thin section, pore sizes from mercury injection, and rock quality indicators

(ii) "Standard" tests are conducted on these samples. Our standard testing suite varies as our objective is to gauge the variability in a parameter important to field development as simply as possible. Some typical standard tests are –
   a. ambient condition, reservoir mobility matched, water-oil end point tests with rate bumps (based on the work in reference [5])

b. high rate (negligible capillary end effect) water-oil unsteady state tests with viscous oils for curve shape
c. “dunk” tests for trapped gas saturation
d. high rate steady state gas-oil relative permeability tests

Figures 1-2 show examples of sample selection techniques –

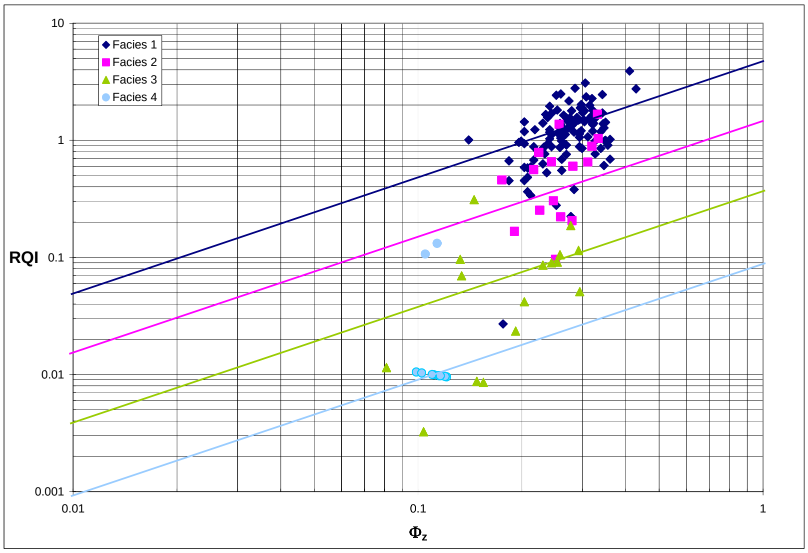
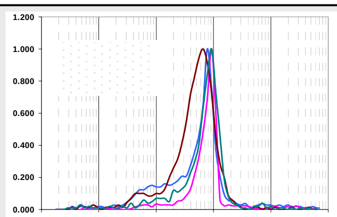
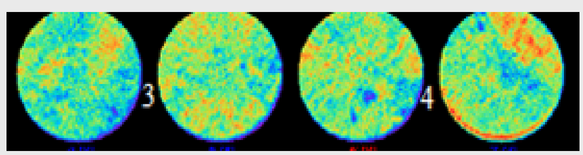


Figure 1: Sample selection using facies identifiers and rock quality index (RQI)





Ranking	Porosity Range (%)	Permeability Range (md)
Very Low (VL)	< 3.99	< 0.01
Low (L)	4-6.99	0.01-0.5
Medium (M)	7-10.99	0.5-3
High (H)	> 11	> 3

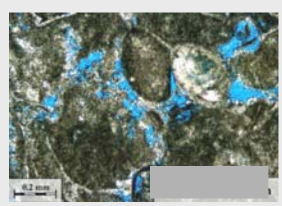


Figure 2: Sample selection using mercury injection, porosity, permeability, CT scans, and thin sections

Our most common standard test is the ambient condition, reservoir mobility matched, water-oil end point tests with rate bumps (based on the work in reference [5]). Figure 3 shows typical results of such tests. The low $K_{rw}@S_{orw}$ and high S_{orw}[1] end point values are

[1] For compatibility with Experimental Design simulation inputs, we refer to this end-point as S_{orw}. However, this point could be at ROS. S_{orw} is residual oil saturation; ROS is remaining oil saturation. ROS $>S_{orw}$. S_{orw} refers to the oil saturation trapped at the pore level under the particular forces being applied.

obtained at reservoir pressure gradients (~ 1 psi/foot). At the end of this low rate flood, the pressure gradient is increased in steps – usually by factor of 2, 5, 10, and 100. For the example in Figure 3, both $K_{rw}@S_{orw}$ and S_{orw} end points changed significantly. Typically, the change in S_{orw} is small (unless we are dealing with carbonates or unconsolidated sands with end screens), but $K_{rw}@S_{orw}$ changes significantly. These changes could be due to reduction in capillary end effects or due to capillary number effects [see [6] for a detailed discussion of these forces]. The former is a laboratory artifact, and high rate data is more representative of field conditions; whereas reservoir rate data is more representative in the latter case.

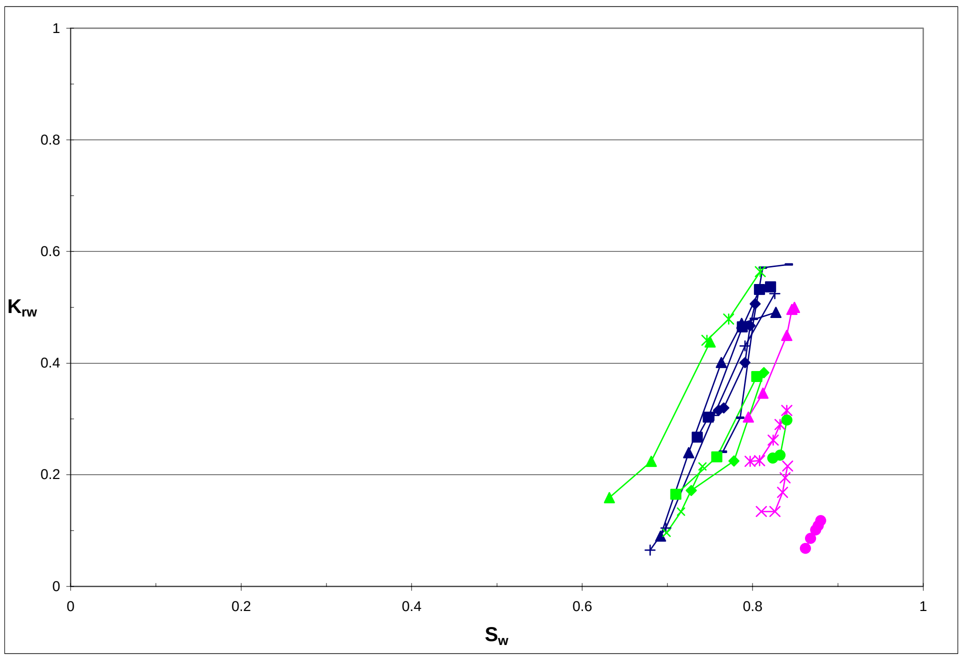


Figure 3: Waterflood end point data. Each data point represents the end point at a given flow rate. The end points change as the flow rate is increased.

Another common test is to generate curve shapes using high rate (minimized capillary end effects) unsteady state tests using viscous laboratory oils. Figure 4 shows a typical result. Water-oil end point bump tests are also shown for comparison.

ROS refers to the oil saturation in the core at the end of a flood – some of it could be at S_{orw}; other regions could be higher than S_{orw} due to capillary end effects, incomplete sweep, or insufficient water though-put.

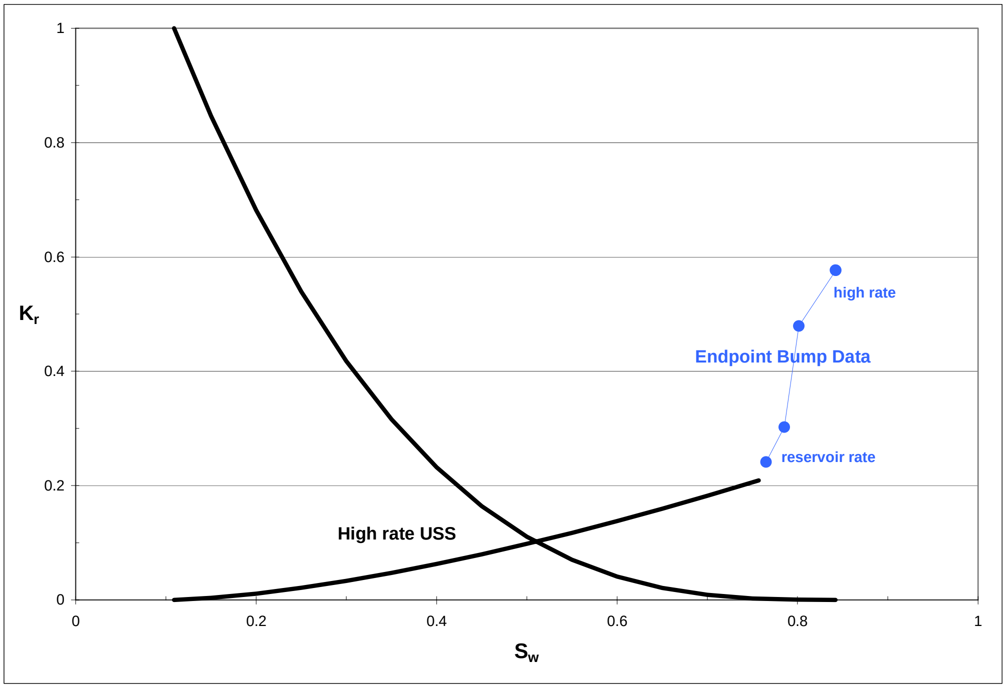


Figure 4: Curve shapes from high rate, unsteady state tests. End point "bump" tests shown for comparison.

2. Process Uncertainty

We select a sub-set of samples either used in or representative of the geological variability tests. These samples are used to probe process issues -- flow rate; wettability; reservoir condition versus ambient; unsteady/steady state versus centrifuge; and effect of mimicking reservoir processes more precisely (depletion, condensate banking, gravity drainage). Our recommendation to our operating companies is to strike a balance between conducting only very simple tests on many samples against conducting very accurate tests on very few samples; and suggest a 50-50 resource split between tests to capture geological variability and process issues.

Flow rate effects are sometimes clearly a result of reducing capillary end effects. Figure 5 is an example where the oil wet end screens on unconsolidated rocks caused large capillary end effects. In such situations, high flow rate gives the best estimate of reservoir behavior. In other cases, the situation in not clear and scanning reveals complex influences of core scale heterogeneity, capillary number, and capillary end effects [6].

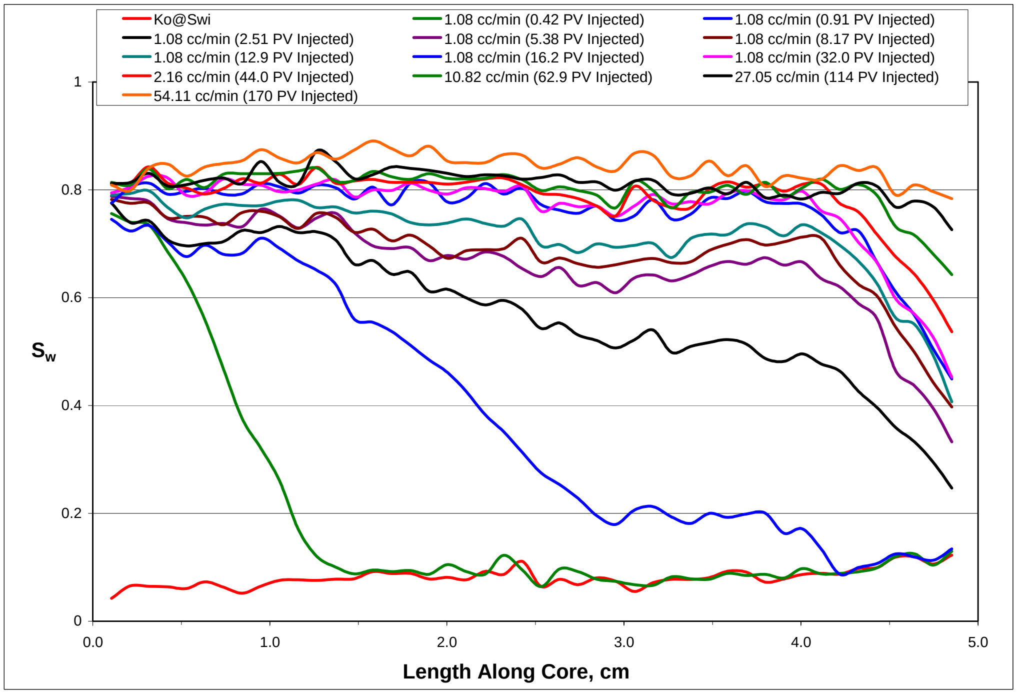


Figure 5: Scanning reveals that flow rate effects are due to reduction in capillary end effects. High permeability, unconsolidated sandstone with end screens.

Process uncertainty also includes the effect of scale-up from the core scale to the simulation grid scale. Issues such as numerical dispersion and large saturation gradients near wells can cause some difficulties, even when there is a clean break in scales, with core scale events being capillary controlled and simulation grid scale events being controlled by viscous forces. The scaling issues is even more problematic if weak capillarity and core scale heterogeneity cause laboratory scale measurements to move from the capillary controlled regime to the viscous-capillary regime [6]; and if the simulation grid contains heterogeneities that also cause viscous-capillary dependencies in the relative permeability curves [7].

3. Subjective Uncertainty

This category contains the element of uncertainty that is not derived strictly from the measured data. It can increase or decrease the overall uncertainty.

We have sometimes found making more measurements increases uncertainty, implying that the early estimates from uncertainty were too narrow. Perhaps the sampling program was too sparse or the process uncertainty was not properly explored in the first data set. Hence it is important to always examine “beliefs and uncertainties” [3], and to look at analog data if the data sets are sparse.

Subjective uncertainty can also reduce the overall uncertainty. A classic example is in the analysis of the results of water-oil end point tests with rate bumps on unconsolidated rocks. These data often show significant change in the endpoints (K_{rw}@S_{orw}, S_{orw}) as the rates are bumped from reservoir rates to high rates. Unless saturation profiles in these floods were measured using x-ray scanning (for example, see Figure 5), our analysis would have to carry this as rate uncertainty. However, we have significant experience in these systems that show the oil wet end screens are the source of the flow rate changes, and it is not due to the competition of capillary number and capillary end effects in the core samples. Hence, high flow rate tests give the best estimate of end points, and we use our experience ("subjective") to reduce overall uncertainty.

FRACTIONAL FLOW THEORY

Fractional flow theory [8] is a simple tool that should always be used by laboratory practioners when designing, interpreting, and creating suitable curves for use in reservoir simulation. We have found plotting oil saturation (S_o) against Pore Volume Injected (PVI) to be particularly useful. PVI is the absolute slope of (dS_o/df_o) where f_o = oil fractional flow.

Fractional flow theory instructs us that only saturation states near S exist when water flooding water wet, light oil reservoirs. Hence, unsteady state water floods conducted in the laboratory can only give us information near the end points. Mixed wet rocks show a larger region of two phase flow. Figure 6 illustrates this point for a light oil reservoir (oil viscosity ~ 0.5 cp) using typical data for water wet and weakly wet rocks. Traditional practice has been to resort to using viscous oils to obtain a significant portion of two phase flow in the laboratory, and to derive the full relative permeability curve. The use of this type of curve in reservoir simulation is not only dubious, but also has potentially incorrect end point data as small scale core heterogeneities may cause viscous fingering.

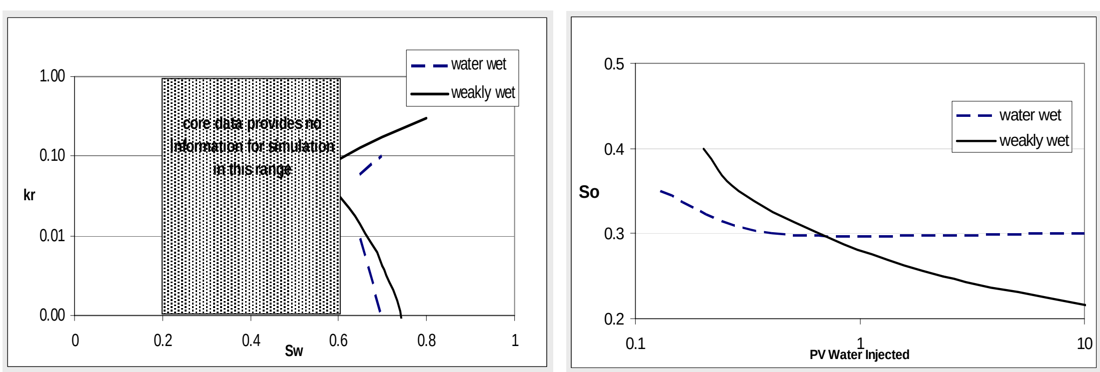


Figure 6: Use of fractional flow theory to understand: (left) regions of useful information from core floods; (right) reduction in oil saturation with PV water injected.

Fractional flow theory can also help us understand if differences between measurement techniques are important. We often note significant differences between gas-oil unsteady state and centrifuge oil relative permeability data, but fractional flow theory usually shows that the differences in predicted S_o are very minor for several PVI, and hence often unimportant when considering gas injection in layered systems. However, the differences may be important if gravity drainage is an important mechanism.

Another example is in the prediction of deliverability of gas condensate reservoirs, where the relationship of K_{rg} to (K_{rg}/K_{ro}) is more important than the actual form of the gas-oil relative permeability curves [9]. This point is made very well by Nagarajan, Honarpour, and Sampath [10] where they first compare the actual relative permeability data for reservoir and model fluids, and then in the form K_{rg} versus (K_{rg}/K_{ro}). It is difficult to gauge from the raw relative permeability data if changing the fluid type will materially affect predictions; it is much more obvious from the second comparison.

GENERATION OF P10-50-90 CURVES

We will use an example from a field undergoing water flooding to discuss generation of P10-50-90 curves. We first need to define the criteria we will use to generate these curves. Typically this is oil recovery versus PVI of water. The P10 curve represents the scenario that there is less than a 10% chance that the oil recovery will be worse; P50 is 50%, and P90 is 90%. Typical steps comprise –

1. Range of end points are from the bump rate tests

2. Range of curve shapes encompass
    - Shapes from original high rate, high viscosity unsteady state tests
    - Altered shapes caused by extrapolation to the end points of the bump tests

3. The above ranges are then used to create S_o versus PVI plots using reservoir water and oil viscosity values.

4. P10-50-90 curves are then picked from these plots, and the underlying relative permeability data are used as P10-50-90 curves for reservoir simulation studies.

Figures 7 and 8 show an example application of this process --

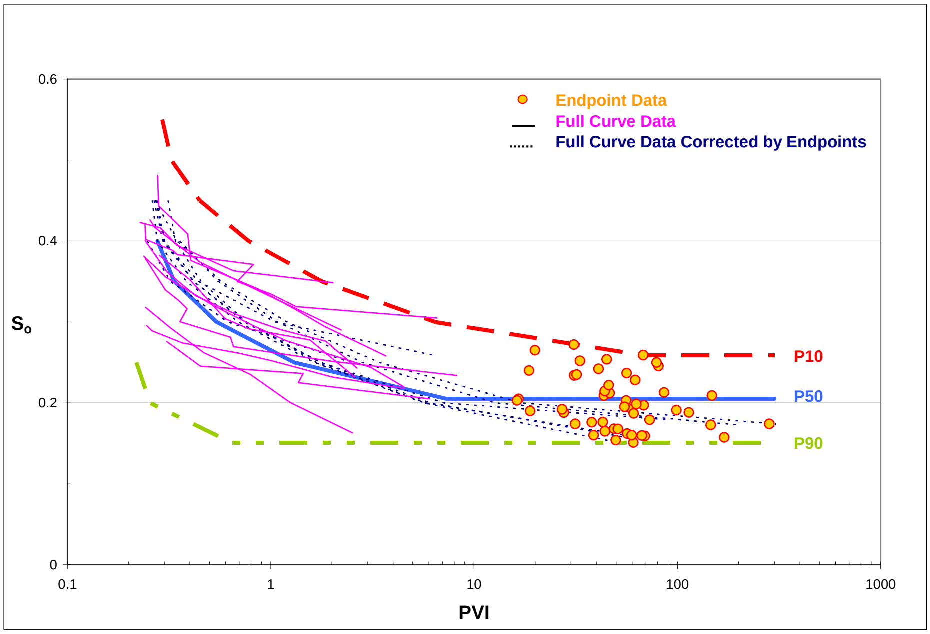


Figure 7: Selection of P10-50-90 curves using S_o versus PVI information

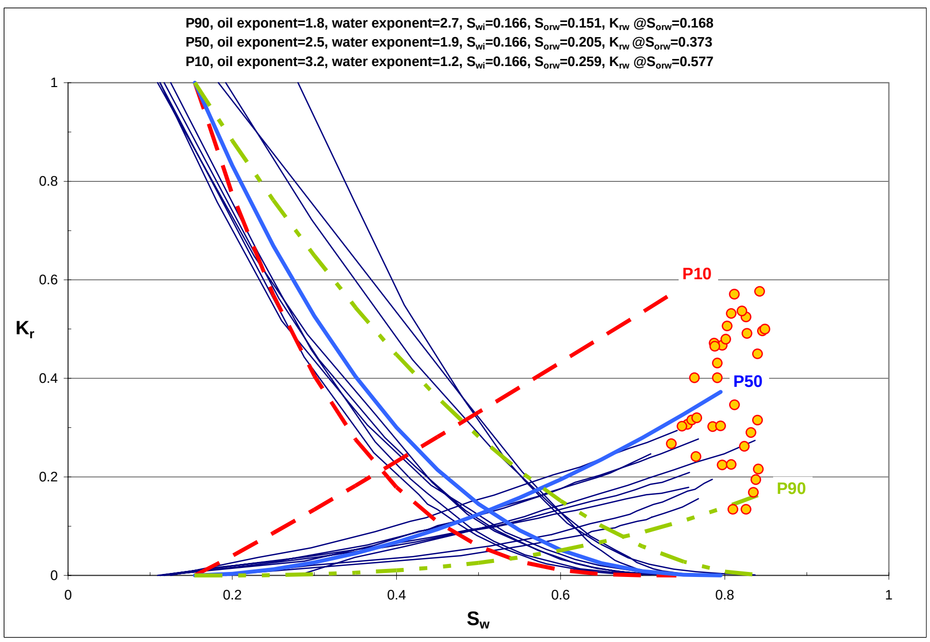


Figure 8: The relative permeability curves underlying the P10-50-90 selection in Figure 7

In some studies, there is a step between 2 and 3 above, where we do scale up studies to alter the range to reflect change in scale. We may also check the effect of using straight line relative permeability or relative permeability with water hold-up, as some of Chevron's senior simulation engineers find that this is what history matching exercises sometimes indicate.

CONCLUSIONS

Core analysts can be more effective when they focus on the end use and impact of their data. It is not fruitful to insist only on reservoir condition testing with saturation scanning, or only on inexpensive, approximate tests. We are using a simple framework, which is currently evolving, to help us focus on the business impact of our measurements. The basic elements of this framework are capturing the sources of uncertainty (geological, process, subjective) so as to allow us to understand where we need to focus to reduce it; and to use fractional flow theory to guide where the data is useful and where it makes an impact.

NOMENCLATURE

K_r = relative permeability
PVI = pore volume injected
fo = oil fractional flow
ROS = remaining oil saturation
S = saturation
S_{orw} = residual oil saturation
g = gas
o = oil
w = water

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