CORE ANALYSIS: IS IT REALY WORTH IT?

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ABSTRACT
Discoveries of large petroleum fields in Western Canada and the United States are becoming increasingly rare in recent times. One might therefore question the value added by implementation of expensive laboratory testing, particularly since there are various correlations available to approximate some of the essential parameters that influence reservoir response and subsequent economic return. To address this question, a comparison has been made on the oil recovery and economic viability that can be projected from a hypothetical reservoir with and without the guidance of relative permeability data as derived from laboratory analysis and correlations. A synthetic model was constructed with input of several laboratory-derived relative permeability functions. This model was used as the "Base Field Data". Various simplifications of the reservoir model were then made by assigning in some cases only one set of rock tables, and in others, data that is based upon estimates for the data to be used in Corey type relative permeability correlation. The model output was run through an economic analysis, and comparisons of cashflow and profitability were made. It was found that significant gaps exist in the annual cashflow projections. As some corporations live and die on cashflow projections, the gathering of laboratory data that will enhance production forecasts should be viewed as a necessary step in field development and management.

INTRODUCTION
There is a subtle shift occurring in the how petroleum reservoir exploitation is valued by some operating companies, particularly in North America. There has been a proliferation of smaller and more aggressive oil companies, which being driven by the stock market, are placing less of an emphasis on long term profitability, and more of an emphasis on annual and quarterly cashflow, as derived from hydrocarbon resources. Less of an emphasis is placed on long term profitability as a key performance measure.

Cashflow is in the annual profitability, either before or after taxation; net present value ("NPV") is the summation of the discounted cashflow series. Cashflow is a short term performance measure, while NPV is long-term in nature. Cashflow determines how a company can fund future growth options, or retire debt. One of the most determining factors in the majority of projects is the revenue stream. A focus on revenue growth will do more for the company in the long term than a focus on operating cost reduction. Revenue growth is accomplished by a strong effort at exploration combined with an equally strong effort towards field development and management. Once found, a field's value will be realized by a sound development strategy which is the result of competent geologic and engineering efforts.

To optimize cashflow and NPV, reservoir characterization of a hydrocarbon deposit is essential. Understanding the reservoir will lead to sound decisions on investment, or divestment, alternatives. The key components of reservoir characterization are an understanding of the rocks, and the fluids contained within the rocks. The tools that are available for the purpose of reservoir characterization are geologic information, routine core analysis data, special core analysis data, fluid PVT studies, and numerical reservoir simulation. The simulator is used to tune the model data to field and production data. Once characterized, the various development options can be simulated and evaluated for economic merit.

The input data will cost money. The focus of this paper is on the aspect of special core analysis, specifically, oil-water relative permeability curves. This data can cost upwards of $15,000 Canadian for a single piece of rock. The value of the expenditure may not be appreciated by those who are unfamiliar with this aspect of reservoir engineering, who may see the expenditure as superfluous. We will demonstrate that if insufficient saturation function data is gathered, then dramatic departures from reality can result which can lead to poor decisions being made.

Reservoir simulation is a highly unconstrained exercise, and the number of degrees of freedom is enormous. To arrive at a reasonable model that characterizes the reservoir, some elements of the data set must be defined and fixed. Should the collection and use of basic data be neglected, the resulting history match can range from poor to physically unrealistic. Such a model would then result in poor reservoir performance prediction, which will lead to the potential for bad investment decisions. Considering waterflood operations, such bad investment decisions may range from sub-optimal waterflood operation design to selling a property with unrealized potential.

We address the value addition that can come about by gathering basic information on a hypothetical oil reservoir regarding how the reservoir can be expected to perform under various operating conditions. The method involves a comparison of the performance of a hypothetical reservoir, based upon variations of the oil and water relative permeability input data. All other input data was held constant between runs, so that an even comparison could be made.

We do not fully explore all aspects of the information gathering process, nor the detrimental impact if insufficient data is gathered. We do not fully explore the infinite possible variations in relative permeability data. This is not meant to be a discourse on relative permeability determination, or scale-up, or pseudo-curve generation. Rather, we outline a process to demonstrate one possible method for quantifying the value of such laboratory data.

OVERVIEW

The method for quantifying the value of gathering saturation functions was to use a combination of laboratory data, established correlations, and numerical simulation. Simulation was used to generate production forecasts, which were the basis for establishing value. This value was quantified using economic evaluation.

The only variation between the various simulation input data sets was the saturation functions. The saturation data sets were established by three methods classified as follows:

Class 1: Estimation of saturation endpoint data, and Corey relative permeability correlation estimating No and Nw;
Class 2: Laboratory determined saturation functions, which was fitted with Corey correlation relative permeability curves;
Class 3: Laboratory determined saturation endpoint data; Corey relative permeability correlation estimating No and Nw.

Analogue fields in the area were used to estimate the input parameters described above.

The correlations used to generate the relative permeability functions were based upon the Corey approach[1]. A normalized water and oil saturation variable is defined, from which the relative permeability functions are derived. The normalized water and oil saturations are defined as

$S_{w,e} = (S_w - S_{w,irr}) / (1 - S_{w,irr} - S_{o,rw})$
$S_{o,e} = 1 - S_{w,e}$

The relative permeability to water and oil are then defined as follows:

$K_{rw} (S_w) = K_{rw}(S_{o,rw}) * (S_{w,e})^{N,w}$
$K_{ro}(S_w) = K_{ro}(S_{w,irr}) * (S_{o,e})^{N,o})$

DESCRIPTION OF SIMULATION MODELS

EXODUS[2], a commercial black oil numerical simulation program was the reservoir simulation engine. The various simulation models had as input the same values for thickness, PVT tables, rock compressibility, depth, initial datum pressure, well locations and operating constraints, and so forth. These are outlined in Table 1. For a given location in space, the rock properties such as porosity and absolute permeability were also held constant. A typical porosity distribution is shown in Figure 1. A permeability - porosity crossplot function was used to generate the permeability distribution from the porosity distribution. This function is shown in Figure 2, and the resulting map for permeability is shown in Figure 3 for the same layer as the porosity map in Figure 1.

The only independent variable that was allowed to vary between input data sets was the assigned saturation table at a given location in the reservoir. The assignment of the saturation table was based upon the porosity of the rock, classified as high, medium, and low quality rock type. These correspond to rock tables 1, 2, and 3 respectively. The rock table initialization for the various models were keyed off of the porosity values. An example of the rock table number initialization for runs SCA001, SCA005, and SCA009 is shown in Figure 4. The lower quality rocks, as defined by lower porosity and permeability, have a saturation function of 3, corresponding to the dark shading. Similarly, the higher quality rocks have high porosity and permeability and have light shading. For the other runs, the saturation tables were assigned as a single value for all grid cells. Details of the descriptions of the simulation models is provided in Table 3.

The first four simulation models, SCA001 through SCA004, used Class 1 saturation functions. The parameters used to define these saturation functions are shown in Table 4. The oil and water relative permeability functions that result from this input data are shown in Figure 5. The simulation models SCA005 through SCA008 used Class 2 saturation functions. The laboratory data is shown in Figure 7, and the associated Corey correlation parameters that match this data are provided in Table 4. The last four simulation models, SCA009 through SCA012, used Class 3 saturation functions. The estimates for the Corey exponents Nw and No were made, and the endpoint saturation data, as determined in the laboratory, are shown in Table 4. The relative permeability curves derived using the Corey relations are shown in Figure 6.

The core plugs used in the laboratory experiments were taken from an Eolian sandstone reservoir. The sand grains were moderately well sorted, rounded, lightly cemented, and medium to fine grain. The oil was light and sweet, and is represented by the PVT data set used in the simulation model. The data was taken from a set of three unsteady state relative permeability experiments which used formation fluids and overburden pressure. The cores were aged under oil at irreducible water saturation for six weeks prior to testing. Each of the three laboratory experiments was conducted on a core of different porosity and permeability, ranging from "low" to "high". The oil PVT properties are provided in Figure 9. The gas PVT properties are provided in Figures 8.

Two patterns were simulated, and each pattern was an inverted five spot with approximately 85 acres per pattern. The simulations were set up to have one year of primary production, followed by 9 years of waterflood operation. The voidage replacement ratio for all runs was targeted to maintain constant reservoir pressure.

DESCRIPTION OF ECONOMIC ANALYSIS METHOD:

The output from the various simulation runs, specifically, the well flow rates, were used as input into an economic evaluation package. This package is a commercial product known as PEEP(3) ("Petroleum Economics Evaluation Package"), distributed by Merak Products. The intent was to quantify the differential values for the profitability of the various runs. The focus was, in particular, to examine the differentials between the cases where data was assumed, and the cases that utilized laboratory data. This differential, in terms of either net present value or cashflow, can then be viewed as the value of the laboratory data. Decisions are made based upon the production forecast economics, and any activity that increases the accuracy of the forecast will have value.

The performance measures used to quantify economic value included Net Present Value at 10% Discounting ("NPV10"), Payout Period, Rate of Return ("ROR"), and the Profit to Investment Ratio at 10% Discounting ("PIR10").

Parameters used in the economic analysis, independent of flow rates, are provided in Table 2.

TECHNICAL RESULTS AND DISCUSSION OF SIMULATION MODELS

The production of oil is shown in Figures 10 through 12 for the various simulation runs. Significant differences were observed in the initial oil in place for the various models, as would be expected from the different saturation endpoints. For example, model SCA001 has an initial oil in place of 1,793,364 m3, whereas model SCA005 has an initial oil in place of 1,611,062 m3, a difference of over one million barrels.

In Figure 10, the oil production is plotted as a function of time, for SCA001 - SCA004. In Figure 11, the oil production is plotted for SCA005 - SCA008. In Figure 12, the oil production is plotted for SCA009 - SCA012. It is observed that there are significant differences between the various model outcomes.

It is essential that enough data is gathered on a subject reservoir to characterize the behavior of the various types of pore systems in the reservoir. In each of these figures, the oil production is compared between a model with three sets of rock tables (the first line series in each plot), and models with a single rock table uniformly applied to the reservoir.

It is well accepted that reservoirs are heterogeneous at virtually any scale. The aspect of heterogeneity applies to all facets of the reservoir, including rock saturation functions. A single saturation function is insufficient to characterize and entire reservoir. If a rock type representing high rock quality is applied across the entire reservoir, the predicted oil production can be expected to be far greater than what would be expected from a non-uniform rock type system. This is reflected by the first and second series in each of Figures 10 - 12. Similarly, if a rock type representing low quality rock is applied to the reservoir, performance is underpredicted. The consequence of these results is particularly pertinent for the realm of acquisition and divestment decisions, where a company can literally give away millions of dollars of unrealized potential. Similarly, a purchaser could acquire an asset for far above its true market value.

Second, comparisons of oil production and recovery were made. The cumulative oil production after 10 years of operation for models SCA001, SCA005, and SCA009 were 600 E3m3, 610 E3m3, and 750 E3m3 respectively. These are quite similar, but the recovery and the production rate profiles differ. The oil recovery for the three models as a percentage of stock tank oil initially in place is 33.3%, 38.6%, and 37.7% respectively. The rate of oil production is fundamental, as it impacts facility design and overall project economics. Each model has a production rate profile that differs from other models.

The fluid movement through the reservoir was examined by monitoring the saturation profiles. There were found to be striking differences regarding how the water sweeps through the reservoir. This is a critical consideration should infill drilling (horizontal or vertical) be contemplated.

ECONOMIC RESULTS OF SIMULATION MODELS

The production profiles from the simulation models were input into the PEEP program, a commercial petroleum economic evaluation package. The results are tabulated in Table 5.

In this simulation study, it was a surprise that the completely uncollaborated set of relative permeability curves (SCA001) resulted in similar NPV10 as the model with a full data set (SCA005). It was coincidence that brought the output from the two models close together. This is borne out by examination of the cashflow profiles, which show strikingly different profiles. Figure 13 shows the after tax annual cashflow profile, and the discounted cumulative cashflow profile. It is observed each of the profiles on an annual basis is quite different than the others. Completely synthetic data (SCA001) underpredicts "actual" performance (SCA005) over the first four years. Similarly, the run with endpoint data and correlation generated relative permeability exhibits a higher than actual cashflow profile.

To incorrectly predict the future outcome of investment decisions can result in economic damage to the corporation. Uncertainty can be removed by spending what may amount to "pocketchange" to gather information via basic laboratory studies. Efforts to contain costs are necessary, but should not be performed arbitrarily or at the expense of the asset.

CONCLUSIONS

The following conclusions are put forward:

1) Basic and fundamental data has value, as it will lead to an enhanced understanding of reservoir performance. Without this information, more degrees of freedom are introduced into the model.
2) Reservoirs are heterogeneous, and simulation models must reflect this
3) Considering relative permeability curves, the data used in this study illustrates that it is the transient or intermediate saturation data that will ultimately determine production rates. Data for

the full saturation range should be experimentally obtained, as the rate of production will have a profound influence upon the facilities design and the overall economics.

4) The value of laboratory data can be demonstrated by a "look-back" process, where the value for the expenditure can be quantified by a process similar to that outlined here.

REFERENCES

1. Dria, D. E., Pope, G.A., Sepehrnoori, K, Three-Phase Gas/Oil/Brine Relative Permeabilities Measured Under CO2 Flooding Conditions, SPERE, Vol. 8, No. 2, May 1993.
2. T.T & Associates, Exodus Implicit Compositional Model V. 3.00, August 1997.
3. Merak Projects, Canadian Peep Version V 97.2.0.1 August 1997.

Fluid Properties:		
Oil Density	850	kg/m3
Gas Specific Gravity	0.7	
Bubble Point Pressure	18250	kPaa
Reservoir Properties and Dimensions:		
Initial Datum Pressure	22250	kPaa
Net Pay	25	m
Del X	30	m
Del Y	28.5	m
Patterns:	2	
Acres per pattern	84.5	acres

Table 1: Fluid and Reservoir properties

10 year run
Oil Price: $18.50 US / bbl real 1998$, flat
Gas Price: $1.85/mscf real 1998$, flat
Exchange Rate: $0.70 US / $ Canadian
Capital Expenditures:
$10 million for all wells
$2.5 million for primary facilities
$2.0 million for water injection facilities
Operating Expenditures:
2.5% overhead on operating expenses
2.5% overhead on capital expenses
$0.5 million per year fixed
$19/m3 oil
$12.5/m3 water injection
Royalties and Taxes
as specified in provincial and federal legislation

Table 2: Economic modeling parameters

Case:	Endpoints	Intermediate	Rock Type Initialized:
SCA001	Synthetic	Synthetic	High, Medium, and Low quality
SCA002	Synthetic	Synthetic	Only High quality
SCA003	Synthetic	Synthetic	Only Medium quality
SCA004	Synthetic	Synthetic	Only Low quality
SCA005	Laboratory	Laboratory	High, Medium, and Low quality
SCA006	Laboratory	Laboratory	Only High quality
SCA007	Laboratory	Laboratory	Only Medium quality
SCA008	Laboratory	Laboratory	Only Low quality
SCA009	Laboratory	Synthetic	High, Medium, and Low quality
SCA010	Laboratory	Synthetic	Only High quality
SCA011	Laboratory	Synthetic	Only Medium quality
SCA012	Laboratory	Synthetic	Only Low quality
SCA015	Laboratory	Laboratory	High, Medium, and Low quality
SCA016	Synthetic	Synthetic	High, Medium, and Low quality

Table 3: Model Relative Permeability Variations

Model Input:	SCA001 - SCA004 Rock Quality Represented:			SCA005 - SCA008 Rock Quality Represented:			SCA009 - SCA012 Rock Quality Represented:		
	High	Medium	Low	High	Medium	Low	High	Medium	Low
Porosity (fraction)	0.27	0.23	0.19	0.2	0.175	0.15	0.27	0.23	0.19
Absolute Permeability (md)	750	75	7.5	750	75	7.5	750	75	7.5
Sw,irr	0.2	0.28	0.36	0.328	0.343	0.297	0.328	0.343	0.297
Sor,w	0.25	0.32	0.39	0.168	0.272	0.448	0.168	0.272	0.448
Kro(Sw,irr)	0.8	0.65	0.4	0.8	0.8	0.8	0.8	0.8	0.8
Krw(Sor,w)	0.25	0.2	0.1	0.2131	0.3812	0.0631	0.2131	0.3812	0.0631
No	3	3.2	3.4	2.2	3.2	1.7	3	3.2	3.4
Nw	2	2.2	2.6	2.75	3.05	3.3	2	2.2	2.6

Table 4: Origin of input for Relative Permeability functions

	NPV10 $K	Payout months	ROR %	PIR10 $/$
SCA001	6397	32.2	73.5	0.46
SCA002	14012	11.7	0	1.02
SCA003	2462	42.6	36.7	0.18
SCA004	4013	0	0	0
SCA005	6357	33.2	74.9	0.46
SCA006	12768	31.1	98.9	0.93
SCA007	3091	35.6	49.7	0.22
SCA008	588	24.8	34	0.04
SCA009	8563	100.1	29.2	0.62
SCA010	14255	108.7	29.8	1.04
SCA011	4930	76.4	29.7	0.36
SCA012	434	27.2	26.3	0.03

Table 5: Economic Performance measures for the various simulation models

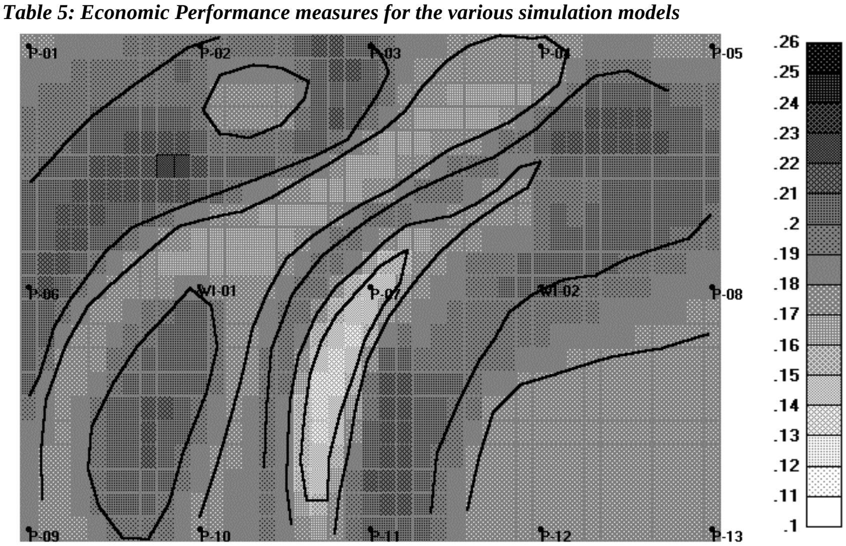

Figure 1: Layer 1 Porosity (fraction)

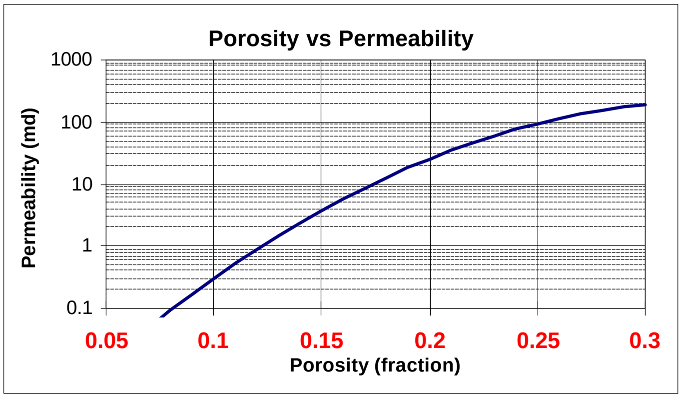

Figure 2: Porosity - Permeability cross plot function

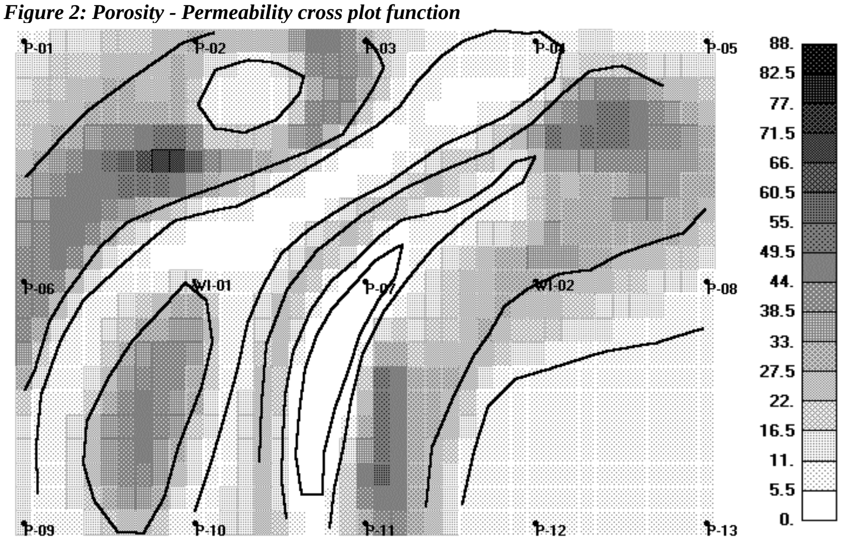

Figure 3: Layer 1 Horizontal Permeability (millidarcy)

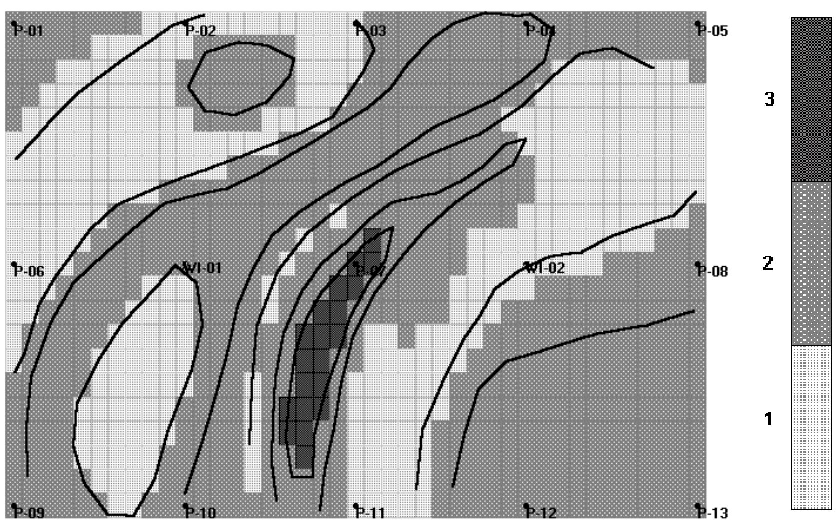

Figure 4: Layer 1 Saturation Function Key

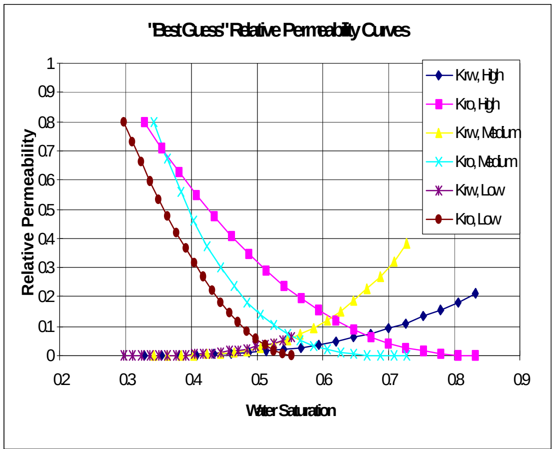

Figure 5: "Best Guess" Relative Permeability Functions

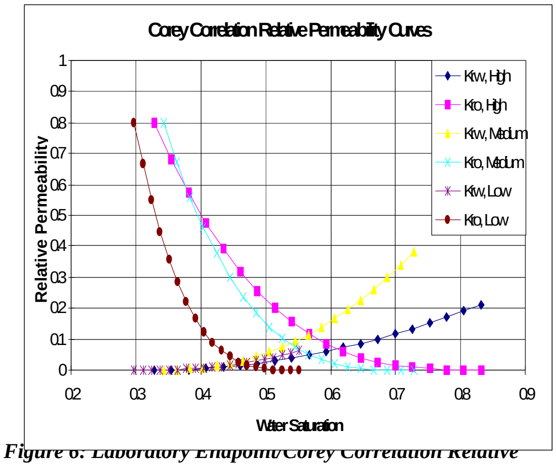

Figure 6: Laboratory Endpoint/Corey Correlation Relative Permeability Functions

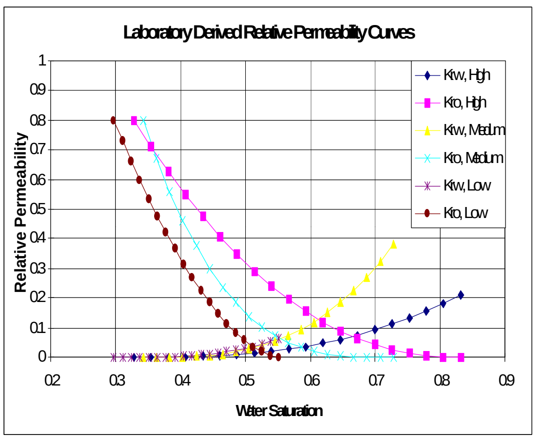

Figure 7: Laboratory Determined Relative Permeability Functions

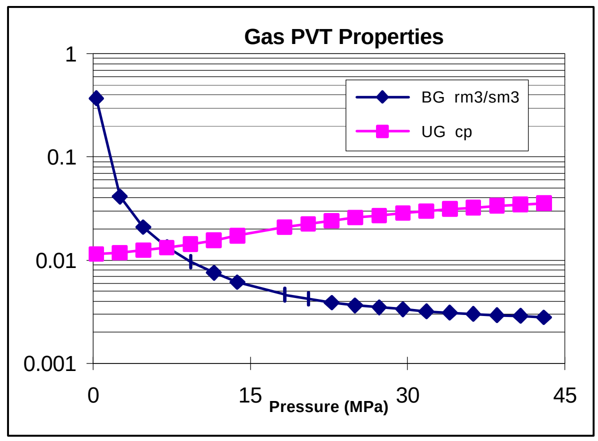

Figure 8: Gas PVT Properties

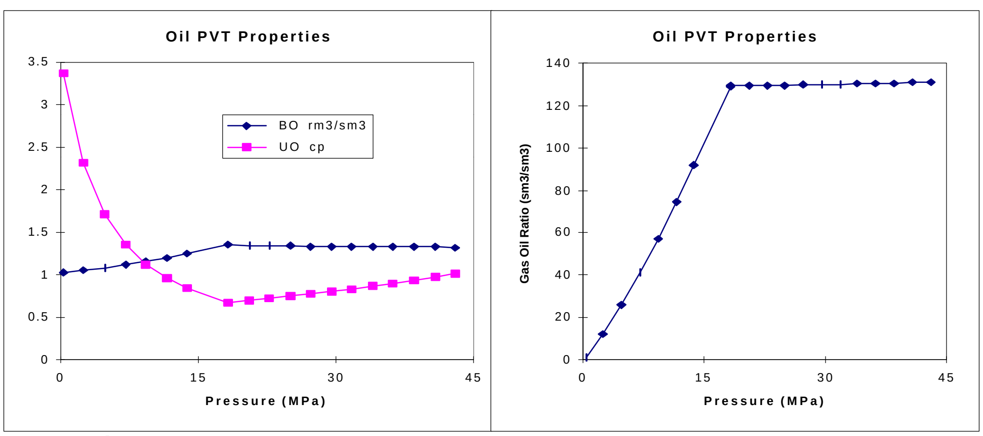

Figure 9: Oil PVT Properties

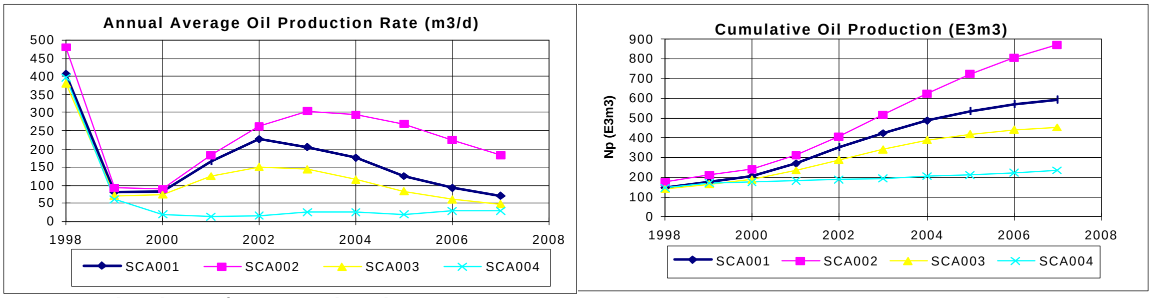

Figure 10: Oil production for SCA001 through SCA004

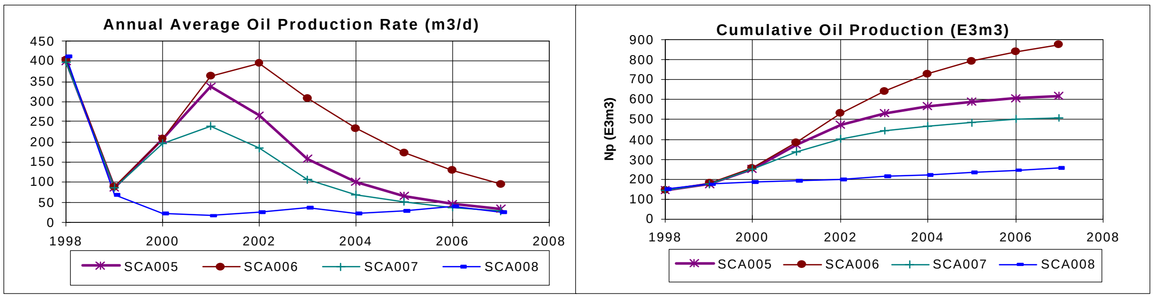

Figure 11: Oil production for SCA005 through SCA008

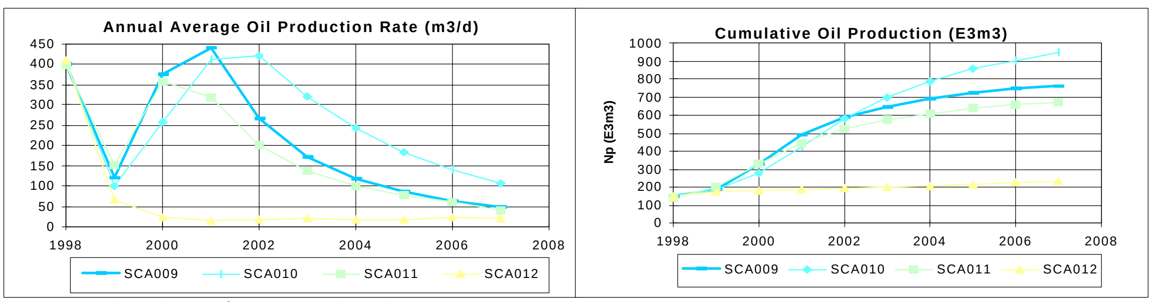

Figure 12: Oil production for SCA009 through SCA012

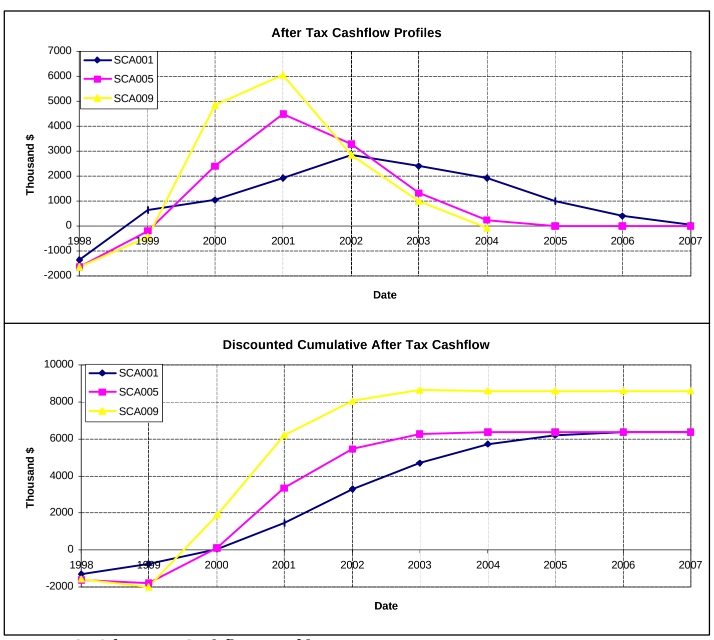

Figure 13: After Tax Cashflow profiles