THE VALUE ADDED FROM PROPER CORE ANALYSIS

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ABSTRACT
Oil companies will always be dependent upon quality data from different sources for optimum field development. Core analysis data, as well as seismic data, geological information and data from well testing, establish a fundamental basis for the understanding of a hydrocarbon reservoirs storage and production potential. Further, the nature of different reservoirs may vary substantially, with respect to geometry, origin and content. Hence, reservoirs must be modelled individually. Nevertheless, rock properties data are frequently copied from literature or analogues because of lack of experimental data. The motivation behind this paper is to focus on the importance of proper laboratory data from core analysis. Important steps towards a comprehensive core analysis programme include; core catching, rock characterisation, and selection of representative rock types, fluids and conditions. The core analysis programme itself should be designed to represent the actual reservoir challenges with respect to fluids in place and future displacement processes. Further, implementation of resulting data into a full field model is of major importance for the design of the actual laboratory preparations and displacement processes. This paper uses real field and core analysis programmes to illustrate the consequences of decisions based on wrong core (or right) analysis programmes or results.

INTRODUCTION AND MOTIVATION
Figure 1 illustrates a typical life for a reservoir or field from planning to abandonment. As can be seen core data should preferentially be included at several stages. In the very early phase core data is needed to assess the storage potential from thin section analysis, core description, measurements of porosity and primary drainage capillary pressure. Further, dimensioning of processing facilities and selection of completion strategy, will need dynamic and rock stability data. These analyses are frequently combined with data typically acquired from well logs (density, gamma, resistivity and NMR response), to be able to convert well logs into valid rock characterisation parameters. During the appraisal and development period, new targets may be identified, which frequently will raise the need of more core and core analysis data. It could also be that new development strategies evolve in the initial phase, and these should be tested through process oriented laboratory experiments. During the production phase, the reservoir models will be updated by history matching. This may result in even more core analysis data focused on specific rock types or areas of the field or reservoir. Finally, changes in production strategy and economy may validate screening of EOR potentials in the mature phase, leading to targeted experimental programme with specific EOR methods tested in the laboratory.

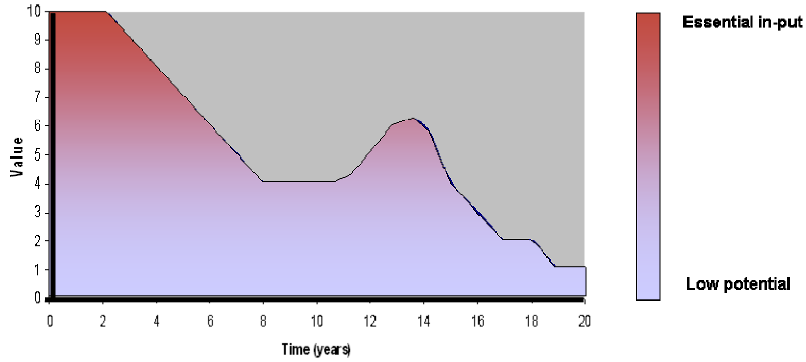


Figure 1: Value of core analysis data during a field life

An article in Financial Report by CIBC World Markets Corp. (April 13, 2004) discusses the importance of core analysis by referring to the commonly used formula for reserve estimation per acre-foot:

$$OIIP = \frac{7758\Phi(1-S_w)}{FVF_o} \tag{1}$$

It can be stipulated from (1) that the error range possible in calculating porosity Φ from the logging technique can result in an over- or under-estimation in reserves of up to 20%. Hence, reduction of this uncertainty by calibration of well log response to core analysis data is of vital importance.

DESIGN OF A CORE ANALYSIS PROGRAMME

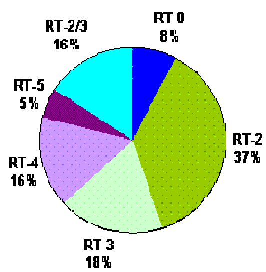
The first challenge in the design of a core analysis programme is to secure representative core material and fluids for the laboratory tests. The first phase is to ensure that representative parts of the reservoir rock and fluids, are actually received by the laboratory. Hence, the wells drilling programme should be planned in detail with respect to coring of the important parts of the reservoir, retrieval of core material from reservoir to surface, surface handling, and transport to the laboratory. Further, sufficient volumes of representative fluids should be sampled if reservoir condition testing is a part of the experimental programme. Such plans should evaluate the need of special actions (mud selection, low invasion drilling, tripping speed, surface handling).

ResLab as a service company, has several examples from around the world of improper core handling. This varies from poor storage of core material (drying out, wettability change), via poor core handling (physical damage and fracture generation) to coring of unrepresentative zones. Hence, several core analysis programmes have been either cancelled or postponed until new representative core material has been available. For some projects it has been decided to continue the programme with the uncertainty of not having ideal or representative core material. In most cases representative core material could have been recovered if care had been taken in the planning of the coring and core handling process.

The next step is to select core plugs from representative depth intervals. Sometimes, especially for homogeneous zones in clastic material, zones can relatively easily be identified by visual inspection of the core. However, for heterogeneous materials special emphasis must be given. In such cases a thorough rock characterization study will be necessary, with the aim of identifying different reservoir rock types (Lucia (1995)), and prediction of importance with respect to both storage and production potential. The final step will then be to pick a representative selection of core plugs for the focused laboratory experiments. The samples from a well may range from non-reservoir to moderate or good quality rocks. Hence, storage capacity and permeability may vary from good to poor.

A rock typing sequence should include fraction (of total cored material) represented by the different rock qualities. The example in Figure 2 from a carbonate reservoir shows that 45% of the wells core material is represented by poor reservoir quality dolomites (RT-0 and RT-2). More detailed results from the rock characterization of the wells define these rock types to consist of poorly developed microporous intercrystalline pore systems. Flow through these samples is generally expected to be minimal. 34% of the core material is represented by poor to moderate reservoir quality dolomites (RT-2/3 and RT-3) dominated by microporous intercrystalline pore systems. Flow through these samples is also expected to be minimal. Finally, 21% of the core material shows moderate to good reservoir quality (RT 4 and RT 5) where the pore system consists of intercrystalline macropores.

Relative Abundance of Rock-types



Rock-type	Number of samples	Kl (mD)			He Por. (%)		
		Max	Min	Average	Max	Min	Average
0	3	0.02	0.01	0.01	3.43	0.45	1.5
2	11	13.7	0.03	0.60	11.1	5.98	10.0
3	5	8.59	1.14	2.35	14.6	7.97	11.1
4	2	9.29	1.76	4.04	17.4	13.4	15.4
5	1	4.62	4.62	4.62	16.3	16.3	16.3
2/3	5	6.25	0.20	0.96	12.0	0.20	10.5

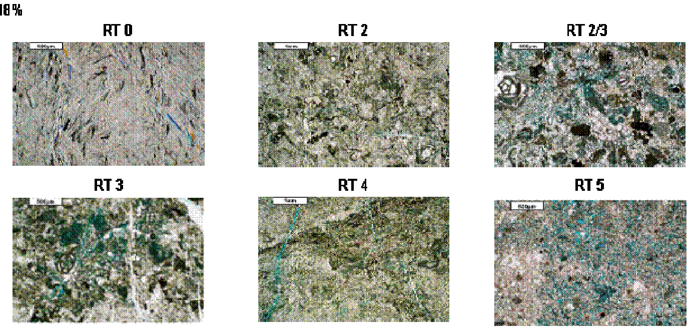


Figure 2: Rock characterization of a carbonate reservoir

Dependent upon the objective for further core analysis programme it is of essential value that the main part of core plugs reflects the results from the rock characterization programme.

CORE ANALYSIS – IMPACT ON RESERVOIR DEVELOPMENT

The fist two field examples show that the actual core analysis programme does not have to be very advanced to make an impact on the reservoir performance. However, in order to obtain representative results the core plugs to be analysed must be carefully selected, and data should be evaluated and validated by the reservoir management team immediately.

Example 1: Conventional Core Analysis

Formation A is a low permeability gas reservoir (Hjelmeland and Dennis (2005)). The formation is productive in the field, which has 3 of 5 sands located within this formation. Traditional cut-offs in this formation are 12% porosity and 0.01 mD permeability. Most productive intervals are evaluated based on log evaluation, mostly porosity and Qv calculated from logs. A 9 meter core was taken at the top of sand unit no. 4, from the 20th well drilled in the development phase of the field. Log analysis of the well indicated that the A4 sand unit had average of 10.5 -11% porosity, and no test was recommended for the interval. The core analysis results were in good agreement with the log porosity, and permeability was in the range of 0.006 to 0.011 mD. However, comparisons were made between this well and material from other wells with core analysis information, and tortuosity values obtained. The permeability ratios from conventional core analysis in this well indicated that the pore system was actually less tortuous than other productive sands with 13-14% porosity and >.05 mD permeability. Based on the above findings it was decided to test the A4 sand, despite the fact that this sand had been tested in two previous wells in the field with very disappointing results. Table 1 shows the contribution from the different sands in this well.

Table 1: Production rates from different reservoir intervals

Sand	Production rate (mmcfgd)
A1	1.7
A2	1.4
A3	0
A4	400
A5	800

Reserves added by the contribution from A4 sand for this well alone (within the predicted drainage area for the well – recoverable production above dew point) was 75mmcf (@ USD 5.00 per mcf = 450,000 US incremental value of well). The operators own numbers shows the following cost benefit ratio:

Cost for analysis of 9 meter core: USD 3500
Cost of downhole logs for the well: USD 45000
Cost: benefit for logs – this interval: none
Cost : benefit for doing core analysis: 1:129

Example 2: Rock Strength

Another example comes from Field B discovered in 2001 in the tertiary basin of Veracruz. The formation is weakly consolidated Sandstone with gas production. The reservoir was originally thought of as analogue to a gas field in an adjacent structure. Wells test identified two –three productive sandstones yielding approx 8 -9 mmcfgd. Major development effort for the field took place early 2002 in conjunction with building surface facilities to handle gas. Four wells were initially opened up on 5/16" – 3/8" chokes each well averaging approximately 8 mmcfgpd initially. However, after 20 days the production had dropped to between 1.5 and 3 mmcfgpd. Five months before opening the first wells, a potential problem was diagnosed in a core analysis routine report. For reservoir data in-put to new structures, copying industry published values for compressibility when estimating reserves or doing field simulation work is very common. However, the published values are based on typical sandstone and carbonate rocks with simple rock – pore systems. It was not realized in the initial evaluation phase of the field that compressibility values for Field B were often scattered with one or two trends apparent:

- The higher the porosity values, the lower compressibility was measured (contrary to models and published data (Li et al.,(2004)).
- Higher compressibility values were found in moderately good reservoir rock, although due to increasing clay, the quality of rock was reduced significantly along a rather small range of porosity values (see Figure 3)
- Grain arrangement (sorting) has an effect on compressibility (Table 2, Figure 4 and 5)

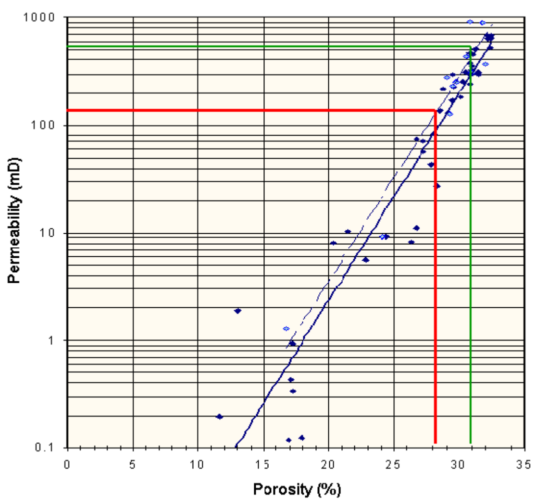


Figure 3: Porosity and permeability cross-plot Field B

In Figure 3 the green bars show that at 31% porosity, the permeability averages above 400 mD. The red bar shows that with a 3% difference in porosity, the permeability drops to less than 150 mD, a third of it's original value.

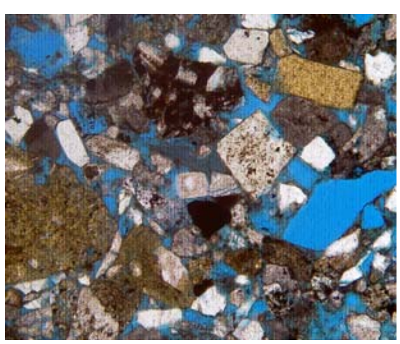


Figure 4: Thin section photo

Figure 4 shows poorly sorted sandstone. The point count shows that the rock is poor in quartz and rich in rock fragments.

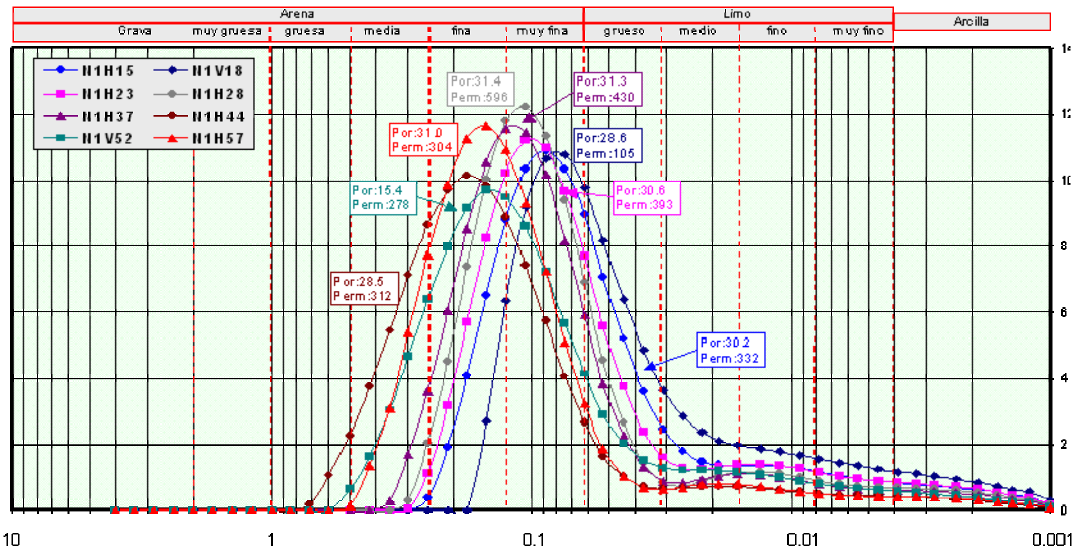


Figure 5: Pore throat size distribution from mercury injection experiments

When first recognizing problem, the field chokes were immediately dropped to 1/16”. This was done without much loss in production. The field was studied to insure that the sandstone reservoirs were large enough to sustain production. Two replacement wells were drilled to replace the poorest performers. Although the wells produce from highly permeable formations, the zones of interest were completed with a frac pak adding proppant grains to the formation that are not ductile and resistant to compression. The wells initially produced at 120 mmcfgd and still produce more than 8mmcfgd 3 years later.

Table 2: Results from confining pressure measurements

Confining Pressure (psi)	**Accumulated Volume Displaced (ml)**	**Pore Volume (ml)**	**Norm. Pore Volume (frac)**	**Porosity (frac)**
800	0.000	5.033	1.000	0.325
1300	0.168	4.865	0.967	0.318
2000	0.260	4.773	0.948	0.314
3000	0.427	4.606	0.915	0.306
4000	0.510	4.523	0.899	0.302
5000	0.622	4.411	0.877	0.297
6000	0.735	4.298	0.854	0.292
7000	0.946	4.087	0.812	0.281
8000	1.113	3.920	0.779	0.273
9000	1.273	3.760	0.747	0.265
10000	**1.441**	**3.592**	**0.714**	**0.256**

By replacement of initial rock properties in the model (from analogues), to representative core analysis data, the reservoir displacement is now much more efficient. Further, the insight provided by the recent, relatively simple core analysis programme, has saved the operator from drilling a large number of additional wells, and hence considerably reduced the development costs for the field.

REPRESENTATIVE CONDITIONS FOR LABORATORY EXPERIMENTS

When the actual core plugs for the special core analysis programme have been selected, it is needed to define the analysis protocol. There is quite a degree of variation between the oil companies' preferred core analysis protocols; from analysis on native core at reservoir conditions with live reservoir fluids, to cleaned core at ambient conditions using laboratory oil and nitrogen. However, based on our recent experience, the mostly used protocol seems to be to perform the experiments at reservoir conditions, with dead or live oil, after cleaning and ageing.

Independently of the preferred conditions for the experiments, it is necessary to establish representative initial saturations prior to a relative permeability experiment. Normally, the laboratory will attempt to establish a water saturation close to Swirr. However, for transition zone studies initial water saturation will be targeted to the reservoir height under investigation, Swi > Swirr. A non-representative initial water saturation prior to a water or a gas flood, may generate non-representative data (i.e. not representative saturation interval, hysteresis). Further, wettability to the rock material should be known prior to defining the experimental parameters (displacement rate, bump) for the relative permeability test (Peters and Flock (1981), and Rapoport and Leas (1953)).

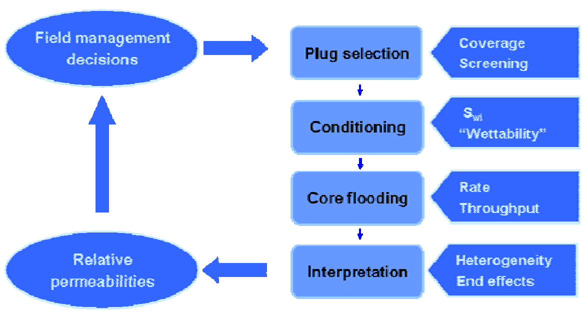


Figure 6: Core analysis role in field management (Spearing et al., 2002)

Figure 6 summarizes the importance of core analysis data for field management when the need is identified. Further, the figure highlights some of the important steps and important factors in the experimental sequence.

Typical field management decision would be to select the field production or displacement scheme. Depending on the type, content and size of the reservoir potential scenarios would be:

- Depletion only (mostly relevant for dry gas reservoirs)
- Aquifer encroachment
- Pressure maintenance & secondary recovery
- Oil rim (or condensate) recovery
- EOR strategies
- Late life depletion

The different scenarios will require different type of data from laboratory experiments, and hence the experiments should target the actual processes planned for the reservoirs.

FIELD BEHAVIOUR AND LABORATORY EXPERIMENTS

Fluid flow is controlled by a combination of viscous, capillary and gravitational forces. It is important to be aware of the relative importance of these forces in the reservoir and laboratory processes. Table 3 indicates the relative importance of these forces on a reservoir scale and a laboratory scale. (it may not look like this for all reservoir types). However, Table 3 implies that capillary forces can completely dominate a laboratory experiment, but can be ignored for the reservoir scale simulations.

Table 3: Relative importance of displacement forces

Force	Reservoir Scale	Laboratory Scale
Gravity	✔ ✔ ✔	✔
Viscous	✔ ✔	✔ ✔
Capillary	✔	✔ ✔ ✔

PROCESS FOCUSED LABORATORY EXPERIMENTS

The next field example focuses on the importance of actually simulate the displacement processes in the reservoir, and to fully understand the dominating forces in the reservoir as well as in the laboratory.

Example 3: Water Flood and Gas Cap Depletion

The reservoir in question consists of highly unconsolidated and high permeability sandstone (8 Darcy), with 30-33% porosity. The reservoir oil has a viscosity of 80 cP. The reservoir temperature is low (30.5 ºC), and expected reservoir pressure of 1270 psia. Four different areas were cored:

- Upper Sand – oil leg
- Upper Sand – gas leg
- Lower Sand (core of poor quality)
- Jurassic Sand – oil leg

Figure 7 shows the planned development strategy, with horizontal producers placed in the oil column. Coning/cusping of water and gas is expected during production. At the end of Phase 1 the situation is expected to be as described above. After this, new producers will be drilled at the top of the reservoir structure to produce the upper part of the oil column, along with the accumulated gas. In-put data from such a production plan, at least for the upper part of the reservoir, will not be obtained from a standard relative permeability test. Hence, a more process-focused special core analysis programme was planned, similar to the process described in Figure 6. These processes needed input from;

1. Gas/oil drainage (expansion of gas cap)
2. Water/oil imbibition (water moving upwards)
3. Water and oil displacing gas in gas displaced regions (Phase 2)

Further, it will be crucial for the generation of relative permeability data for the simulation that all the laboratory effects are understood and accounted for, before the curves are implemented in the reservoir simulation model. Hence, also capillary pressure curves for the equivalent displacements were obtained.

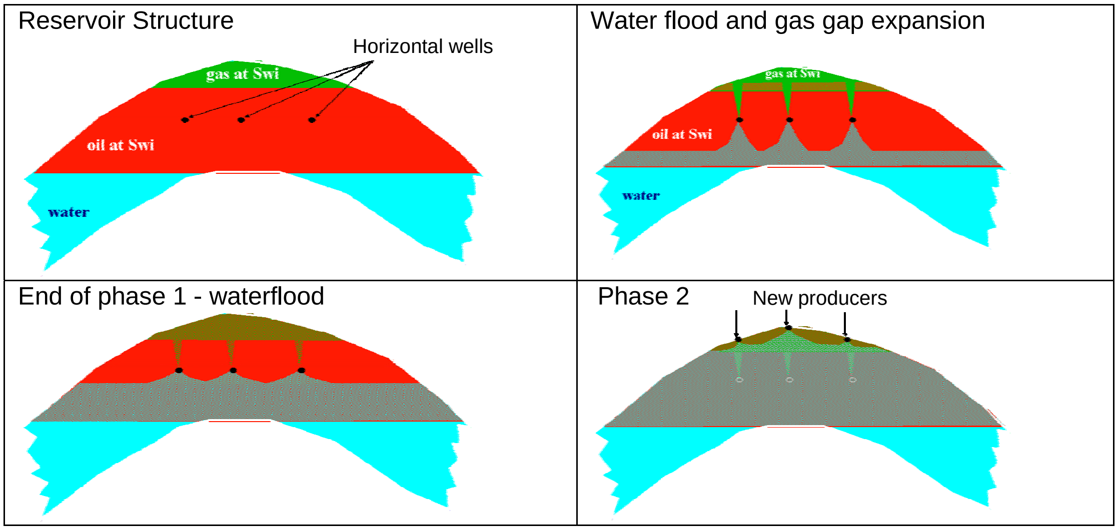


Figure 7: Well locations and fluid movement towards producers (from Spearing et al. (2003))

Oil leg measurements were designed to generate water-oil imbibition relative permeability curves. Figure 8 shows in-situ saturation scans from the displacement on a composite core. As can bee seen from the figure, the saturation profiles are far from uniform. Hence, it was concluded that a standard JBN analysis (Johnson et al. (1959), Jones and Roszelle (1978)) of these data will produce dubious results. For comparisons and quantification of the effect of the outlet end effect, the JBN curve and the corrected simulated curve are compared. Figure 9 shows the calculated relative permeability results. As can bee seen, interpretation of the laboratory experiment without correction for the laboratory effect, has a huge impact on the simulation in-put. In this case the effect is so large that the JBN is clearly misleading, and will probably lead to wrong reservoir management decisions. Several authors have reported similar results, of varying magnitude, in the past (see for instance Kokkedee et al. 1996)).

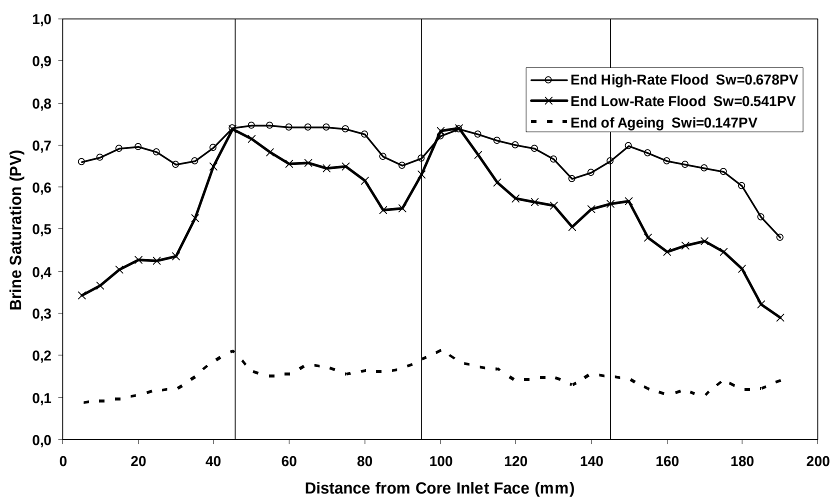


Figure 8: In-situ saturation scans from waterflood (from Spearing et al. (2003))

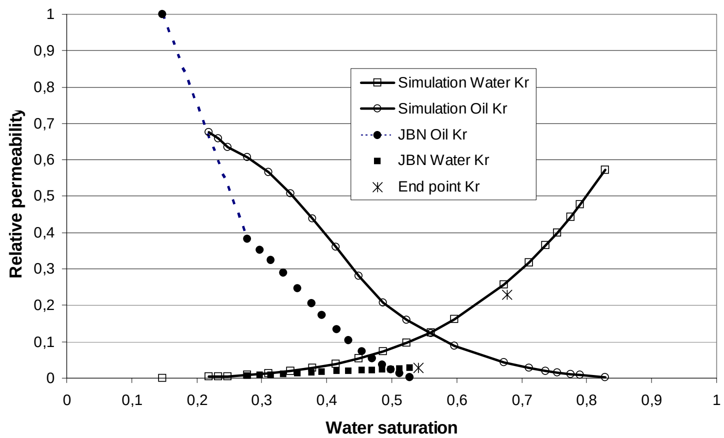


Figure 9: Effect of laboratory effects on JBN calculations (from Spearing et al. (2003))

In fact, prior to obtaining the results above, the field's development plan was based on three water/oil relative permeability experiments measured in 1992. No secondary gas or tertiary water displacement were modelled in the laboratory. These experiments were done on the same oil and sand, and data are expected to be comparable. The old data from 1992 were interpreted by JBN only, without in situ saturation monitoring, and compare well with the recent JBN interpretations. The study also included gas oil drainage curves as well as water/oil/gas displacements to model the effects dominating Phase 2 of the development plan (see Figure 7).

This case study illustrates the benefits of a thorough understanding of the reservoir processes before the SCAL study is designed – in cooperation between laboratory analysts and client. The study should be focused on key measurements Relevant for the expected recovery mechanisms. Case study also illustrates the importance of "best practise" techniques to reduce risk in reservoir management decisions.

Example 4: Middle East Carbonate Reservoir

Two major SCAL studies have been undertaken on 2 carbonate reservoirs from the Middle East. Both studies covered conventional core analysis (including thorough rock characterization), petrophysics, water flood, gas flood and miscible gas displacement. The objective was to obtain representative data for reservoir simulation and to reduce uncertainty. The client's reservoir engineers initially had SCAL data from an old study, and also data from analogues. Initial data set for Reservoir 1 was very limited with:

- No rock type classification
- No CT scanning to aid plug selection
- Pc data by centrifuge air/brine only
- Drainage process
- No imbibition water/oil Pc
- Initial water saturations did not match log data and extremely variable

Further, the earlier floods were performed at ambient conditions using laboratory, or non-representative fluids, without ageing. Since in-situ saturation measurements were not used and neither bump rates at the end, it was impossible to quantify the potential end-effects in the laboratory experiments. Hence, for the new study it was decided to use preserved samples (chosen after careful rock typing). Homogeneous plugs were chosen from the representative zones by CT scanning. The plugs were then cleaned to a water wet state by hot solvent flood, and not dried before saturated by Synthetic Formation Water. Representativity was then checked by measurement of pore volume and permeability. Target Swi was obtained by porous plate with in-situ saturation to check uniform saturation. The next step was to age the plugs in live oil at reservoir temperature and pore pressure for 3 to 4 weeks, with live oil replacement each week . Displacement experiments were performed both by the USS and SS methods at reservoir temperature and pore pressure, and with in-situ saturation monitoring throughout. For all the new experiments core flood simulation was a part of the data interpretation. Updated relative permeability curves from the most recent waterfloods are compared with the old data in Figure 10.

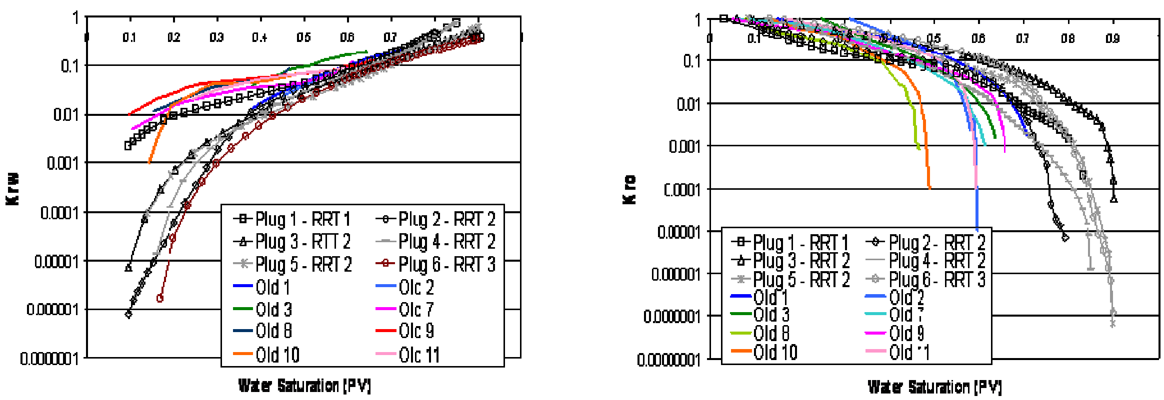


Figure 10: Relative permeability curves

Figure 10 clearly reveals the benefit of more representative water oil experiments. As can easily be seen the recently obtained relative permeability curves will have a large impact on simulated reservoir behaviour (i.e. lower water relative permeability in the early phase, and much higher oil relative permeability towards residual oil saturation).

CONCLUSION

This work shows examples of the benefits from performing carefully planned and process oriented core analysis. All the different steps from core catching and transport, to actual laboratory techniques and experimental conditions, need careful planning to obtain results with a minimum of uncertainties. The two first examples show that by proper implementation of results from basic laboratory tests, this can give the reservoir management team vital information for further displacement and production strategy. Finally, due to new laboratory techniques and interpretation tools, core analysis will for some cases reveal information which is crucial for field management decisions, also in the late stage of a field's life (shown by examples 2 and 3).

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NOMENCLATURE

FVFo:	Formation Volume Factor of Oil
OIIP:	Oil Initially In Place (barrels of stock tank oil per acre-foot)
Φ:	Porosity
Sw:	Water Saturation
Swi:	Initial Water Saturation
Swirr	Irreducible Water Saturation

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