CORE ANALYSIS TO CALIBRATE WELL LOG INTERPRETATION.

Jan Rafdal
Enterprise Oil Norge Ltd

Abstract Coring and logging (electrical coring) has contributed greatly to the understanding of the petrophysical properties of reservoir rocks and the dynamic behaviour of reservoirs for the last 70 years. Today it is seldom seen that wells are drilled without being logged, and quite a high percentage are being cored. This paper deals with the integration of core and log data to determine lithology, estimate porosity, net/gross ratio, fluid saturations, permeability and other petrophysical parameters. The analysis relates both to the static and dynamic description of reservoirs. Attention is also given to the merits of core and log analysis with respect to the dynamic behaviour of reservoirs.

INTRODUCTION

The common goal in the oil industry, to maximize the net revenue from the hydrocarbon-bearing resources that we discover and develop, can be sumarized in the following equation :

$$\text{Profit} = f(A * H * N/G * Ø * S_h * R)$$

where:

	$A*H$	=	Gross rock volume,
	N/G	=	Net to gross ratio,
	$Ø$	=	Porosity,
	S_h	=	Hydrocarbon saturation,
	R	=	Recovery factor,

This equation illustrates that the economic result is a function f of the volume of hydrocarbons in place in the reservoir at any time. Log Analysis concentrates on quantifying the petrophysical parameters such as N/G, Ø, S_h and input to R.

This article describes some of the applications of cores and core data in Log Analysis (or Formation Evaluation). For the purpose of this paper Log Analysis is defined as:

* Locate productive hydrocarbon-bearing formations around wells.
* Quantify petrophysical properties.
* Determine fluid contacts/properties.

DATA SOURCES

The number of data sources available to the petrophysicist for the analysis of the rocks and reservoir behavior is increasing. Table 1 below describes some sources of data available from cores and logs (Schlumberger tool names have been used):

TABLE 1 Sources of data from cores and logs.

Core analysis	*Log data*
Porosity (Ø)	*Gamma Ray (GR, NGS)*
Permeability (k)	*Density (LDT)*
Grain density	*Neutron (CNL)*
Saturation	*Sonic (BHC)*
Capillary pressure	*Resistivity (ILD,LLD)*
Imbibition	*Microresistivity (MSFL)*
Wettability	*Dipmeter (SHDT, FMS)*
Sponge core	*Repeat Formation Tester (RFT)*
Mechanical	*Electromagnetic Propagation Tool (EPT)*
Relative permeability	*Nuclear Magnetism Log (NML)*
Resistivity Index	*Gamma Spectra Tool (GST)*
Formation Factor	*Production Logging Tool (PLT)*
Corelog	*Sonic Waveform (SDT)*
Core photographs	*Caliper*
Thin sections	*Spontaneous Potential (SP)*
SEM,XRD,mineralogy	*Thermal Decay Tool (TDT)*

In practice, we use MWD logs (GR, Resistivity, Density and Neutron), Mudlog and test/production data in addition to wireline logs and cores. Logs are normally the most abundant data and therefore used for continuous interpretation.

Advances in technology continuously make new improved measurements and experiments available to the industry. Today this process seem to move faster and faster and there is a demand for new standards both for coring (Sprunt et al., 1988) and logging (Wiley and Allen, 1988).

Even with the current possibilities in computer technology, much energy is used in the process of transporting data between different software systems and different formats. A potential for improving acquisition and analysis at reduced cost is obvious.

EVALUATION

Lithology

Lithology in this paper includes a geological description of the formation in terms of sedimentology, petrology, diagenesis and mineralogy. Initially our tools were calibrated to the main lithologies sandstone, limestone and dolomite. The classification of the rocks in terms of lithology is not discussed here. The sources of such information are cuttings, sidewall cores and whole cores. Whole cores are considered the best source for quantitative data. Logs can be calibrated to core data and be used for prediction of mineralogy using, for example the Natural Gamma Spectrometry (NGS) log or the Gamma Spectrometry Tool (GST). In normal cases the combinations of the porosity logs can be used to predict lithology from crossplots or from clustering techniques (also called electrofacies). When properly calibrated to core data, electrofacies can give a useful prediction of lithology and provide the foundation for an improved application of petrophysical models.

Mineralogical information can affect the log analysis (Hurst 1986) as all the logs are functions of the physical and chemical composition of the formation. Our capability to increase our understanding of the log responses in reservoirs and the possibilities of simulating log responses need accurate mineral data from cores. The Element Mineral Catalogue (Schlumberger, 1990) constitutes a reference to measured and theoretical properties of 125 minerals.

Shaly or dirty formations have been and still are one of the major challenges to Log Analysts. Shale/clay can affect both porosity and resistivity logs because their properties are different from the clean lithologies, especially in terms of conductivity. The terms clay and shale have both mineral and grain size definitions and can mean different things to different analysts. Two main directions have been developed for shale correction. One is calculating the shale volume (V_{sh}) from logs as described by Fertl (1987). The other is the measurement of Cation Exchange Capacity (CEC) developed by Waxman and Smits (1968) which is measured on cores. The measurements of CEC can be quite uncertain (Drønen, 1990) and systematic differences may exist between laboratories and measuring techniques.

Figure 1 shows typical occurences and modes of shale/clay in

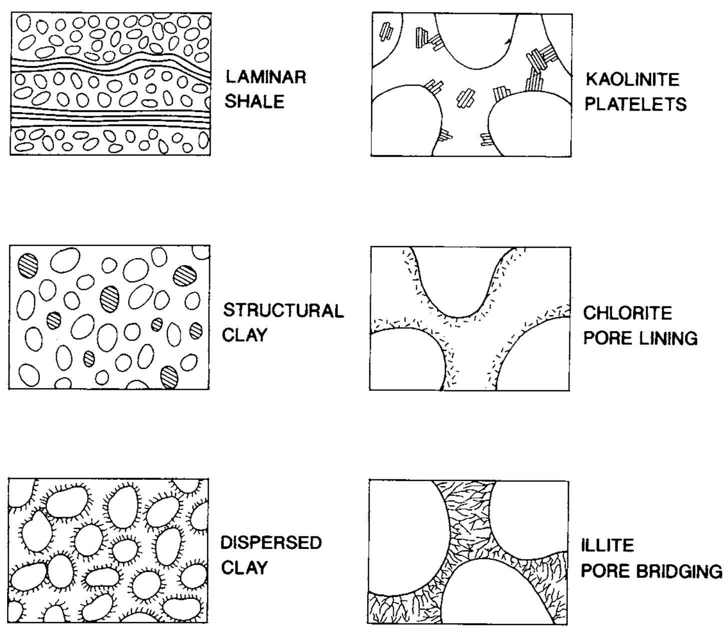


Figure 1 Shaly sandstone, occurrence of shale / clay

sandstones. The petrophysical properties of the rock will be affected according to the type of shale and the way it is distributed. Table 2 below (from Hurst, 1987);(Schlumberger, 1990) describes the variation in properties of four clay minerals:

TABLE 2 Properties of clay minerals.

Clay mineral	Density g/cm^3	Hydrogen index	CEC (mEq/100g)	Natural gamma radioactivity K(%)	Th(ppm)	U(ppm)
Kaolinite	2.60-2.68	0.36	3-5	0.42	6-19	1.5-3.0
Chlorite	2.60-2.96	0.34	10-40	0.1	3-8	
Smectite	2.20-2.70	0.13	80-150	0.16	14-24	2.0-5.0
Illite	2.64-2.69	0.12	10-40	4.5	<2.0	1.5

Porosity

Porosity (Ø) is defined as the ratio of void volume filled with fluids to the bulk volume. Figure 2 (after Juhasz, 1986) shows the unit volume of a sandstone as a function of shaliness. This illustrates the difference between the total and effective porosity. Log porosity can

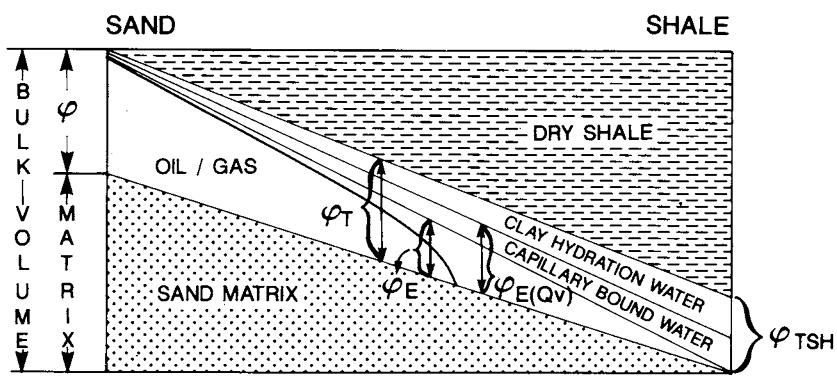


Figure 2 Shaly sand Ø, S_w definitions (after Juhasz, 1986)

be calculated from a tool response equation such as the one below by applying density, neutron, sonic or a combination of those logs. Core measurements can be used to determine the matrix and shale parameters entering the response equations and total porosity can be measured on cores. The following equation is one response equation for porosity logs (Crain, 1986):

$$X = (1 - \varnothing - V_{sh})^*X_{ma} + V_{sh}{}^*X_{sh} + \varnothing^*S_w{}^*X_w + \varnothing(1 - S_w)X_{hc}$$

Where:

$\varnothing$	=	Porosity
X	=	Log value
X_{ma}	=	Matrix log reading
X_{sh}	=	Shale log reading
X_w	=	Formation water log reading
X_{hc}	=	Hydrocarbon log reading
V_{sh}	=	Shale volume
S_w	=	Water Saturation

Sometimes porosity logs are calibrated to core data using a linear fit:

$$\varnothing = A + B^*X$$

where A and B are constants. This may be necessary in some formations where the log responses are not fully understood and core data can not be used to verify log analysis.

Verification is done by comparing average values of porosity over representative zones. Figure 3 shows the comparison between the porosity calculated from the density log and that measured on cores. The lithology is a North Sea Chalk. Low initial net confining pressures have contributed to preservation of porosities approaching

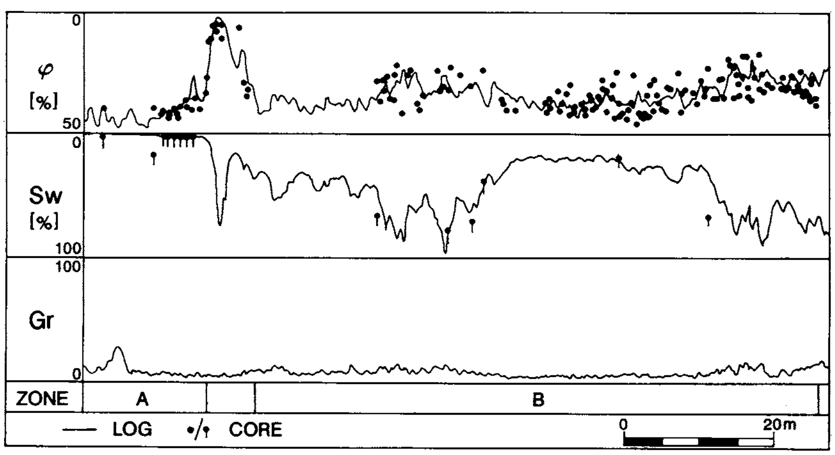


Figure 3 Porosity and saturation from log and core

50 percent. No correction for overburden is assumed to be needed. Formation "B"is a Pelagic Chalk which is laminated and to some degree interbedded with minor amounts of clay in places. The laminations are too thin to be properly defined on the density log, hence the difference in variation of log and core porosity in that formation. Formation "A" is an Allochtonous Chalk which is more homogeneous and therefore do not show such differences. For both formations the core data verify log results because average values over the cored interval agree.

The "mica" sands present in the Brent sandstones in the Northern North Sea is an example of rocks where calibration of logs to core data has been used because K-feldspar and radioactive minerals present in the sands gave a shaly response in relatively clean sandstones. This led to underestimation of porosity and hydrocarbon volume. Detailed core studies have been used in order to understand log responses and define proper petrophysical model.

Saturation

Water saturation (S_w) is defined as that fraction of the pore volume which is filled with water such that the sum of water and hydrocarbon saturations are one ($S_w + S_h = 1$).

About 50 years ago, Archie suggested the following relationship between the resistivity of the rock, formation factor, water saturation and the resistivity of the brine in the formation:

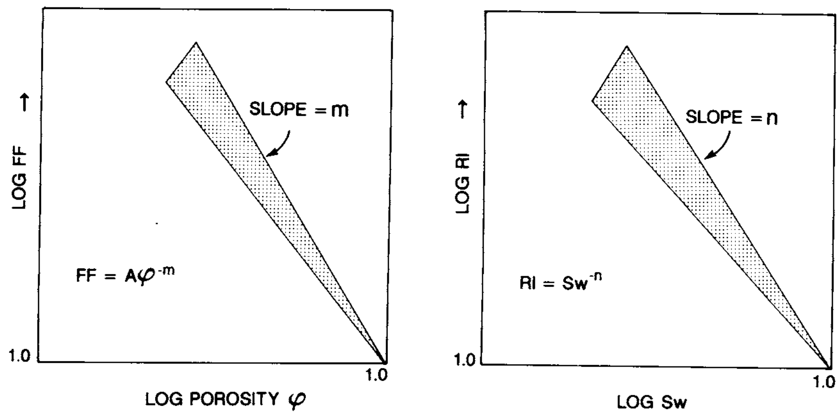
$$R_t = a^*Ø^{-m} * Sw^{-n} * R_w \qquad \text{(Archie, 1942)}$$

Where:

	$Ø$	=	Porosity (fraction)
	R_t	=	Resistivity of virgin zone (ohm m)
	a	=	Lithology factor
	m	=	Cementation exponent
	S_w	=	Water saturation (decimal)
	n	=	Saturation exponent
	R_w	=	Formation water resistivity (ohm m)

Resistivity can be measured by a deep Induction log or any other deep resistivity tool for the interpretation of uninvaded formation. Shallow readings can give the saturation of mud filtrate in the invaded zone (Sxo) which is used for the correction of porosity tools which only sense the flushed zone.

Formation factor (FF) is defined as the ratio of resistivity of a formation saturated with brine to the resistivity of the brine. The measurements are performed on core plugs and when formation factor is plotted versus porosity on a log-log scale, a straight line can be found giving the cementation factor m ($FF=a\varnothing^{-m}$). FF is very dependent on the lithology and the tortuosity of the formation. Figure 4a shows the principle of deriving the formation factor from core data. When core data are not available, porosity and resistivity in clean water bearing zones can be plotted (Pickett-plot) to obtain FF. In both cases it is assumed that only brine is conducting current in the



Figures 4a (left) and 4b Electrical properties of rocks

formation. The resistivity of a formation with 100% water is represented by R_o. When water is displaced with oil the resistivity increases to a new level designated R_t. Resistivity index (RI) is defined as the ratio R_t/R_o. Measurements are performed on core plugs and when S_w is plotted versus RI on a log-log scale, a straight line can be defined with slope "n" which we call the saturation exponent (Figure 4b). This parameter can only be determined from core experiments.

Wettability is a parameter that has been reported to have great effect on the saturation exponent. Experiments indicate that "n" increases with wettability (Donaldson & Siddiqui, 1989);(Morrow, 1990). One problem is that there is no safe way to quantify the *in-situ* wettability. Several parameters such as drilling fluid and cleaning techniques can change wettability and the saturation exponent will depend on the saturation history of the core. It is therefore recommended to be especially careful in the planning and use of electrical measurements.

The well in Figure 3 was cored with oil based mud. The water saturation was calculated using Archie and plotted together with the saturations measured on cores using Dean-Stark method. The core data verify both the very low and the medium range saturations. In the same manner, the saturation of oil measured on cores drilled with water based mud can be used to estimate S_{or} by correction to in-situ conditions. Sponge core taken through flushed zones can give the most accurate measurements of S_{or}.

Shale/clays have different electrical properties from sandstones and limestones, (Table 2) and their effect on resistivity will depend on the type and distribution. Several modifications have been made to Archie's equation to correct for shaliness, as described by Worthington (1985). The shale effect can be illustrated with the following equation:

$$C_t = C_w/FF + X$$

Where:	C_t	=	conductivity of the waterbearing fm.
	C_w	=	conductivity of formation water
	FF	=	formation factor
	X	=	Shale conductivity contribution

The different models try to quantify the X as a function of Q_v or V_{sh} and they use different definitions of porosity (total or effective) in calculations of water saturation.

When using computers for the mapping and volume calculations it is convenient to describe the saturation as a function of porosity and height above a fluid contact. In this process one can use log data alone, core data alone or calibrate the shape of capillary pressure curves to averaged log data. The J-function or similar equations can be used:

$$J = P_c * (k/Ø)^{0.5}/T \qquad \text{(J-function)}$$

Where:	P_c	=	Capillary pressure (psi)
	T	=	Interfacial tension * wetting angle
	k	=	Permeability (md)
	Ø	=	Porosity

This is one way to normalize P_c-curves for a reservoir or a zone within a reservoir. The Free Water Level (P_c=0) has to be known and when permeability and porosity are properly mapped, water saturation can be derived.

Another quick check on the log-derived water saturation is to convert the laboratory-derived P_c-curves to height versus saturation for the reservoir fluids and compare logs and cores in clean formations.

Net/gross

Net-to-gross, N/G, is defined as the ratio of net thickness of formation contributing to production to the gross thickness.

N/G ratio is the result of detailed studies of cores, logs, welltest data and simulation. Very often a cut-off is made on log porosity based on an arbitrary permeability cut-off made by the petrophysicist before mapping. It is of importance to be aware that such a cut-off can cause considerable volumes of fluids to be disregarded in simulation. All interconnected pore volume should be mapped and the cut-off defined in the reservoir analysis process.

In addition to permeability and fluid properties, N/G depends on production mechanism, technology, oil price etc.

Permeability

Permeability is defined as the capacity to flow fluids through the rock.

It can only be measured on cores, by production, testing and with formation pressure testing tools. Normally a correlation can be found between log data and core permeabilities. Correction to *in-situ* conditions can be done by comparison to test results or measurements made in the laboratory under reservoir conditions.

The process of estimating average permeabilities for flow units or reservoir bodies often includes the following steps (after Archer and Wall, 1988):

* Depth shifting, quality control, overburden and fluid correction.

* Check quality of data from logs and cores.

* Establish relationships of Ø vs k (or other relationships).

* Calculate permeability from logs.

* Correction to *in-situ* conditions can be made by comparing average permeabilities to test derived permeability.

Figure 5 illustrates permeability plotted versus porosity for one reservoir and how it can sometimes be related to shaliness or other petrology data here represented by low medium and high GR. Important factors in the understanding of the dynamic behaviour of reservoirs are absolute and relative permeabilities, permeability profile and contrasts. The importance of each of these will vary from field to field and also as a function of time as the fields are depleting.

In certain fields fracture flow can be the most significant contribution to the productivity, such as the North Sea Chalk formations where matrix permeabilities may account for 1 - 10 md and the effective permeability in fractured zones may be up to 100 md. The mapping of such fracture systems for reservoir modelling uses core extensively together with log and test data (Fritsen and Corrigan, 1990).

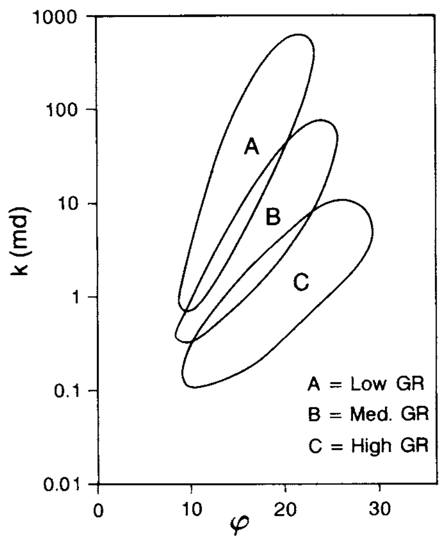


Figure 5 Permeability versus porosity and gamma ray

Published statistics on core measured air permeability (Thomas and Pugh, 1989) showed that industry based practices produce negatively biased results for permeability.

Typical non-trivial issues are depth shifting, quality control, averaging method(s) etc. The next generation of question is how to go from minipermeametry to plugs or dipmeter and beyond.

Fluid contacts

Determination of fluid contacts is critical for determination of STOOIP in the static description and the dynamic behaviour in the producing phase. In the determination of fluid contacts, one tends to combine as many sources of data as possible, such as cores, mudlogs, wireline logs, MWD and test data.

Recovery factor

Recovery factor is defined as that portion of reservoir hydrocarbons in place that can be produced under certain technical and economical assumptions.

It depends on reserves definition (probability), the volumes in place, permeabilities, fluid properties, production facilities, prices, etc. It is dynamic and usually increases with time. Price is the single most important factor influencing the number of EOR projects initiated (Thomas et al., 1989) in USA in the period 1979 - 1986.

Mechanical

Rock mechanical tests are performed in order to understand reservoir mechanisms. Solids productions can be a severe problem in unconsolidated sands and in chalk reservoirs where expensive gravel packs may be needed for solids control.

The mechanical strength is also used to determine parameters for design of fracture stimulation jobs and leak-off prediction in drilling operations. In high porosity chalk fields compaction plays an important role both for the determination of subsidence and reservoir energy. Figure 6 (after Ruddy et al., 1989) illustrates the magnitude of compaction of the high porosity

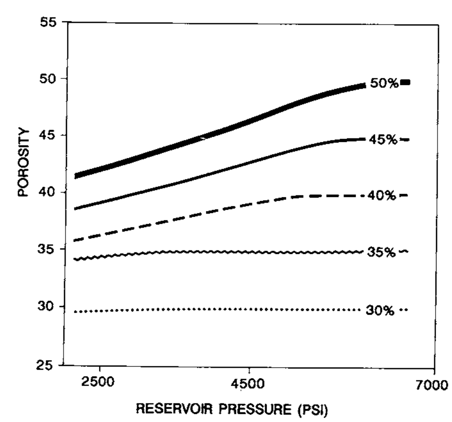


Figure 6 Chalk compaction curves (after Ruddy et al., 1989)

chalk in the Valhall field as a function of reservoir pressure. Initial reservoir pressure was about 6500 psi. The compaction behaviour is based on experiments performed on cores.

PHASES

It can take several decades to explore and develop hydrocarbon resources. It is therefore important to stress that the value of information at one time in a project's life can be quite different from another phase. Evaluation of EOR projects are examples of a phase where it may be recommended to reevaluate completely the reservoir description (Szpakiewics et al., 1987). The manner in which we collect, treat and save information can have great impact in projects performed several decades later.

UNCERTAINTIES

Much work has been undertaken in recent years to investigate the uncertainty of the prediction made by the geoscience diciplines. Rock type, heterogeneities (Weber, 1986), geometry and permeability are field-specific and require different levels of accuracy in different phases of the life of a field.

Development of new and better techniques is constantly giving new and better opportunities to understand the static and dynamic properties of the rock. New microscopes such as SEM and STM give an opportunity to study matter on the nanometer scale. Core tomography (X-ray, NMR,..) give the opportunity to describe cores when preserved and the possibility of monitoring fluid distribution during experiments. We are getting closer to doing our core experiments at reservoir conditions.

Another challenge is that of scales. All the sources of data represent different volumes of rock. This is a problem which always occur when logs are calibrated to core data and when they are calibrated to test information. The volumes and vertical resolutions represented by different measurements are listed in the table below:

TABLE 3 Volumes and vertical resolutions sensed by selected measurements.

Source	*Volume (m^3)*	*Vertical res. (mm)*
Minipermeameter	10^{-9}	*1*
Core plug	10^{-6}	*25*
Microlaterolog	10^{-2}	*50*
Neutron log	*1*	*500*
Laterolog	*3*	*500*
Drill Stem Test	10^{6}	

The process of defining the properties for the flow units often involves the calibration of logs to core measurements. It is obvious that the scaling can be a problem in many cases, but it is also noteworthy that the volume measured on the cores is not even in the volume measured by logs (Haldorsen, 1986).

Often one finds good correlation between average parameters from cores versus those from logs across a geological zone. One major question is always whether the measurements are representative of the *in-situ* conditions. The cores suffer from the process of cutting, decompaction and flushing by mud filtrate, exposure to air and other fluids in the experiments (Longeron et al., 1986);(Worthington et al., 1988). The logs suffer from environmental effects such as borehole fluids, filtrate invasion and shoulder beds.

Thin sands are one problem that has received special attention in recent years. The thin sand reservoirs may be hard to detect and the logs do not give true values. The true properties of the sands can be obtained through core experiments and by running logs such as dipmeter which can be calibrated to core and give good estimates of N/G (Bilsland et al., 1989) and a detailed geological model forms the basis for simulation of the induction log for resistivity estimation. An alternative method is to sample the core by cutting thin slices along the length of the core and compare average values of core on the same vertical resolution as that of the porosity logs (Dahlberg and Fitz, 1988).

CONCLUDING REMARKS

Core analysis forms a basis for the calibration and verification of log analysis in the evaluation of petrophysical parameters for the static and dynamic description of reservoirs.

Improved standards are needed both for logging and core measurements.

Modern computer technology can be used more effectively to further improvements in the reservoir characterization process.

EUROCAS is a positive contribution to the process to stimulate oil companies, research institutions and contracting companies to seek further improvements, through the development of new knowledge and the maintenance of current technology.

REFERENCES

J. S. Archer and C. G. Wall (1986) *Petroleum Engineering : Principles and Practice* Graham & Trotman

G. E. Archie (1942) The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics *Petroleum Transactions of the AIME 146* p. 34-62

M. Bilsland, R. Mobed, E. Cheruvier and J. White (1989) Predicting Hydrocarbon Saturations in Thin Sandstones Drilled with Oil-Based Mud *SPWLA European Symposium, Paris*

E. R. Crain (1986) *The Log Analysis Handbook - Volume I Quantitative Log Analysis Methods* PennWellBooks

K. E. Dahlberg and D. E. Fitz (1988) Comparing Log-Derived and Core-Derived Porosity and Mineralogy in thinly Bedded Reservoirs: an Integrated Approach *SPWLA 29th Annual Logging Symposium*

E. C. Donaldson and T. K. Siddiqui (1989) Relationship Between the Archie Saturation Exponent and Wettability *SPE Formation Evaluation, September 1989*, p.359-362

O. M. Drønen (1990) Oljemetning, Konduktivitet og Ionekonsentrasjon i Skiferhaldig Sandstein *Diploma Thesis*, HSR, Stavanger, Norway

W. H. Fertl (1987) Log-Derived Evaluation of Shaly Clastic Reservoirs *Journal of Petroleum Technology, February 1987*, p. 175-194

A. Fritsen and T. Corrigan (1990) Establishment of a Geological Fracture Model for Dual Porosity Simulations on the Ekofisk Field *The Norwegian Institute of Technology (Graham & Trotman)* p. 173-184

H. H. Haldorsen (1986) Simulator Parameter Assignment and the Problem of Scale in Reservoir Engineering. In *Reservoir Characterization,* Edited by L. W. Lake and H. B. Carroll, Jr. Academic Press, p. 293-339

A. Hurst (1987) Mineralogical analysis and the evaluation of the petrophysical parameter V_{shale} for reservoir description. *Marine and Petroleum Geology,* February 1987, v. 4 p. 82-91

I. Juhasz (1986) Porosity Systems and Petrophysical Models used in Formation Evaluation *SPWLA London Chapter - Porosity Seminar,* September 1986.

D. G. Longeron, M. J. Argaud and J.-P. Feraud (1986) Effect of Overburden Pressure, Nature, and Microscopic Distribution of the Fluids on Electrical Properties of Rock Samples. SPE no. 15383, *61st Annual Technical Conference,* New Orleans, October 1986.

N. R. Morrow (1990) Wettability and Its Effect on Oil Recovery *Journal of Petroleum Technology,* July 1989, v. 42 p. 1476-1484

I. Ruddy, M. A. Anderson, P. D. Patillo, M. Bishlawi and N. Foged (1989) Rock Compressibility, Compaction, and Subsidence in a High-Porosity Chalk Reservoir: A Case Study of Valhall Field. *Journal of Petroleum Technology,* July 1989, p. 741-746

Schlumberger (1990) *Element Mineral Rock Catalog.* Edited by O. Serra.

E. S. Sprunt, W. M. Hensel Jr., C. E. York and M. M. Honarpour (1988) Compilation of Electrical Resistivity Measurements Performed by Twenty-Five Laboratories. *The Log Analyst,* Jan-Feb 1988, p. 13-39

M. Szpakiewics, K. McGee and B. Sharma (1987) Geologic Problems Related to Characterization of Clastic Reservoirs for EOR. *SPE Formation Evaluation,* December 1987, p. 449-460

D. C. Thomas and V. J. Pugh (1989) A Statistical Analysis of the Accuracy and Reproducibility of Standard Core Analysis. *The Log Analyst,* March-April 1989, p. 71-77

R. D. Thomas, G. D. Stosur and J. F. Pautz (1989) Analysis of Trends in U.S.A Enhanced Oil-Recovery Projects. *Journal of Petroleum Science and Engineering* 2 p. 149-157

M. H. Waxman, L. J. M. Smits (1968) Electrical conductivities in oil-bearing shaly sand . *SPE Journal,* v. 8 p. 107-122

K. J. Weber (1986) How heterogeneity affects oil recovery. In *Reservoir Characterization.* Edeited by L. W. Lake and H. B. Carroll, Jr. Academic Press p. 487-543

R. Wiley and L. S. Allen (1988) Recommendation for Neutron Logging from the SPWLA Subcommittee for Log Calibration Guidelines. *The Log Analyst,* May-June 1988, p.204-215

P. F. Worthington (1985) The Evolution of Shaly-Sand Concepts in Reservoir Evaluation. *The Log Analyst,* Jan-Feb 1985, p. 23-40

P. F. Worthington, J. E. Toussaint-Jackson and N. Pallatt (1988) Effect of Sample Preparation upon Saturation Exponent in the Magnus Field, U.K. North Sea. *The Log Analyst,* Jan-Feb 1988, p. 48-53