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RESERVOIR WATER SATURATION MEASURED ON CORES; CASE HISTORIES AND RECOMMENDATIONS

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SUMMARY

Reservoir water saturation distribution from cores is an important data contribution to formation evaluation. The accuracy of the saturation data has often been questionable due to mud invasion. Improvements in coring, doping of mud and analysis in recent years have made saturation from cores much more valuable. The paper presents available methods in the industry with respect to the determination of Sw from cores. This includes planning, doping of mud, coring, sampling, analysis and interpretation. Examples from wells illustrate the importance in using tracer in the mud and drilling samples at the rig site when using water based muds. In most cases with oil based muds no change in water saturation in the center of the core occured. As an extra benefit from accurate core Sw measurements, the salinity of the formation brine in the hydrocarbon column can be determined.

Based on case histories, the paper demonstrates important benefits of obtaining accurate water saturations from fresh cores, in addition to saturation logs and special core analysis: 1) general verification of saturations from logs, 2) arguments for adjusting log interpretation parameters, 3) interpretation in formations with laminations less than log resolution, 4) interpretation in formations with high microporosity. The examples include gas, gas condensate and light oil fields and a broad range of petrophysical and geological properties.

INTRODUCTION

Water saturation distribution is one of the most important parameters for determination of oil-in-place or gas-in-place volumes. Available data from exploration wells to assess the Sw distribution has traditionally been resistivity logs and electrical parameters and capillary pressure data from special core analysis. However, special core analysis determination of n-exponent and Pc-curves can be significantly influenced by sample preparation and testing procedures. Connate water saturation (Swc) from cores drilled with oil based muds (OBM) has long been an industry standard. With water based muds (WBM) contamination from mud filtrate becomes much more an issue in the determination of Swc:

- Water from the mud invades the core ahead of the bit, spurt loss.
- Mud invasion continues in the core barrel, static invasion.
- Mobile fluids in the core are displaced by expansion upon pressure decline during lifting to the surface.
- Further redistribution inside the core and evaporation can take place with time and handling.

There are a number of variables that could affect the degree of mud invasion into the core:

- Drilling parameters: Drill bit, ROP, RPM, overbalance, pump rate.
- Mud characteristics: Filter cake capabilities, stability, additives.
- Oil/Gas properties: High oil viscosity would inhibit invasion. High GOR could displace mobile fluids.
- Formation properties: The spurt loss, or filtrate invasion at the core bit, can be expected to increase with increasing permeability. This is for constant ROP. The static invasion above the bit should decrease with increase in porosity due to higher pore volume to take the filtrate.

The solutions have been to minimise mud invasion by new bits, mud design and coring parameters (Ref. 1). In the case of WBM, some invasion is almost unavoidable and use of a tracer in the mud to correct for invasion is necessary (Ref. 2-3). Fluid expansion could be avoided by using a pressurised core barrel. Since this has practical limitations, implementation of reduced tripping time has been the simplest approach. Although obtaining these corrected Swc data from WBM cores is fairly straightforward in most cases, we find that too often the effort is not made. The aim of this paper is to present methods and recommendations for obtaining Swc from cores, and through field examples demonstrate specific problems and applications.

CORING, SAMPLING AND ANALYSES

To ensure a successful determination of Sw from cores, all involved parties should participate in the planning of the project. This includes the coring company, laboratory, drilling dept. and petrophysisist / reservoir engineer. The main activities for determining Swc from cores in this study include:

1. Dope of the water phase of the mud on the rig with Tritium or Deuterium.
   Take mud samples for background level measurements for every 3-5 meter of cored interval.
2. Core with minimum mud invasion (low overbalance, low pump rate, high ROP).
3. Consider reducing tripping velocity the last few hundred meters to limit the effect of gas expansion.
4. Drill of 1 plug for each meter of core. The plugs should be vertical, from the centre of the core, to avoid the invaded outer zone. Avoid use of water in all core handling. Proper sealing and transportation.
5. Determine water content in the plugs by Dean-Stark extraction in the laboratory.
6. Further cleaning by soxhlet extraction and determination of pore volume, porosity and permeability.
7. Measure concentration of tracer in the extracted water and in the water phase of the mud samples.
8. The laboratory reports Sw in the samples at ambient condition corrected for mud water invasion and salt content. Further corrections are needed for the pressure and temperature effects on the water phase and overburden effect on porosity.

TRACERS FOR DOPING MUDS

Several types of tracers are in use for doping the water phase of drilling muds: Stable isotopes (D_2O or heavy water), radioactive isotopes (Tritium) or chemical salts. Other tracers can be used to dope the non-aqueous phase of a mud (for example Olefins or deuterated hydrocarbon compounds), but these will not be discussed here.

<u>Deuterium Oxide, D_2O, Heavy Water</u>: Heavy water is a non radioactive, non toxic fluid with no health and safety hazards. There are no flight restrictions. D_2O is used in the nuclear industry and there are regulations as to where certain quantities may be shipped and to what purpose it may be used. Deuterium Oxide occurs in nature and the background level in sea and formation water is in the range of 100 ppm to 155 ppm (North Sea 147 ppm). When used as a tracer, the concentration should at least be twice the background, 300 ppm. The fluid is collected together with the Dean-Stark extraction of the plugs. To analyse the D_2O content a mass spectrometer is needed. The costs connected to D_2O are relatively high. For an average North Sea well with oil based mud the cost for the tracer is about US$ 10,000. In addition come analyses that are likely to be more expensive than for Tritium.

<u>Tritium, Tritiated water:</u> Tritium is a radioactive tracer. It is a Beta particle emitter, and necessary safety precautions must be followed. A trained technician from a licensed vendor can handle the tracer. Only small quantities are needed. Less than 500 mCi, or about 10 ml, are added per well. After the tracer has been diluted in the mud, there are no health hazards connected to the Tritium. The Tritium is collected in the Dean-Stark extraction and analysed by a Beta scintillation counter. A mobile unit allows the technician to check the tracer level in the mud at well site. The costs connected to tritium are small; about US$ 1000 for the volume needed in the well.

<u>Chemical tracers, salts:</u> There is a large number of salts that could be added to the water phase of the mud as a tracer. But the common problem is that the Dean-Stark extraction process used to determine the water content of the samples will leave the salts in the samples. These salts may be dissolved and analysed quantitatively, but this is time consuming, costly and a less ideal method.

LABORATORY METHODS

The most common methods to determine saturations are the Retort and Dean-Stark (D-S) extractions. In the D-S method a fresh sample (in our cases a 1.5" diameter plug) from the core centre is weighed and then subjected to an extraction of fluids by boiling solvent. The water is condensed and collected. The oil is determined gravimetrically by weight of the sample before and after extraction. All saturation data in this study were determined by D-S. The D-S extraction leaves the salts in the sample. The water volume can be corrected by either applying a brine salinity/density factor or remove the salt by methanol soxhlet cleaning. To convert the ambient Sw to reservoir Sw one must make standard corrections for temperature and pressure effects on the water phase and pore volume reduction. For a deep reservoir these combined effects can amount to a 10 - 15% relative increase in Sw.

The retort method uses a fresh sample from the core centre. One part is crushed, weighed and heated to 650°C. Evaporated water and oil are condensed and collected. Gas saturation is measured by Hg injection on the other sample part. Saturations of water, oil and gas are then calculated by mass balance.

Determining formation brine salinity: In resistivity log interpretation the formation brine resistivity is set constant and equal to the resistivity interpreted or measured from the aquifer. This resistivity may not necessarily be correct (Ref. 4). As an extra benefit from accurate core Swc analyses it is possible to determine the salinity of the formation brine in the hydrocarbon column. The salts left in the pores after D-S are leached in a known volume of fresh water and the salt content can be determined (Ref. 5).

RESULTS AND DISCUSSION - SW FROM CORES

Properties affecting mud filtrate invasion: A plot of mud invasion from WBM versus permeability for several wells is shown in Figure 1. There appears to be an increase in invasion with increasing permeability. However, the samples taken at the rig site do not show this effect. The mud that invaded the core sides imbibes or diffuses to the center and this effect seems to increase with permeability.

The bottom of the well will experience some filter loss before starting a new core. The top part of each core can therefore be expected to have higher invasion. This is illustrated in Figure 2 where the high invasions of the WBM are from samples taken from the top of each core. To avoid this the first sample should be collected at the bottom end of the first meter or at least some distance away from the top. Other aspects of this figure are discussed below.

With WBM the core is enclosed in mud in the core barrel and static invasion can occur. This is assumed to be a lesser problem than invasion at the bit. The use of Gel Core has been demonstrated to reduce this effect (Ref. 6).

Water based muds: A number of wells have been analysed with respect to Sw and mud invasion. As can be expected, the data shows that significant invasion can occur. The fraction of D-S determined water coming from the mud shows large variations due to different drilling parameters and formation properties. Table 1 shows an example from a core with only a few percent of pore volume invaded. Table 2 shows much higher levels of invasion. The use of a tracer in the mud is necessary to make corrections in Sw. In the Table 2 example, the Sw contribution from the mud is higher than the presumed Swc. Clearly one should be careful in using these results as the water from the mud may have mixed with and displaced some of the Swc brine. This is also demonstrated in the Field Case 4 below, with data from the same well.

Oil based muds: The oil based muds tested typically contain 15 - 35% water as an emulsion. If some of this water contaminates the core it must be quantified and corrected for. Several recent Statoil operated wells drilled with OBM have had the water phase doped with Tritium or Deuterium. The results show that there was no, or just insignificant, invasion of water from OBM into the centre of the cores. No correction of Sw-core due to mud invasion was necessary. The cored formations cover a wide range of properties and lithologies. This agrees with other experiences in the literature, although this was with a mud with far less water content (Ref. 7).

Only in one well there was reported a significant content of tritium in the core, equivant to 4-12% of the total Sw. There are however reports of unstable mud during drilling of this well which was drilled with an olefin based mud. In addition, some of the laboratory data and tracer calibrations were questionable.

Samples drilled at rig site versus in the laboratory: For practical purposes, adding and monitoring tracer in the mud has been performed by the core analysis company. They have also handled the core and drilled vertical plugs from the centre of each core meter interval. Some comparison tests have been made to check the necessity of drilling plugs at rig site, immediately after core retrival, instead of in the core laboratory typically one week later. Figure 3 shows examples of this for WBM wells. The amount of mud filtrate (tracer) increased significantly into the centre of the core for plugs drilled at rig site compared to sampling in the core laboratory about 1 week later. There are also examples of less change in saturation with time, but we recommend to take D-S samples at the rig site in WBM wells. For OBMs the amount of water tracer was close to zero at both sampling sites.

Transition zone and aquifer: In a transition zone the connate water can itself be mobile and may be displaced by mud invasion (both water and oil) and from gas expansion. This is illustrated in Figure 2 where the cores were taken in lower transition and water zone. The points with low calculated Sw also correspond to high invasion points. The high invasion at the top of each core has displaced some of the reservoir brine. At some point into the transition zone the Sw from core extractions may not be trusted. In the aquifer it may be of importance to determine any remaining oil saturation. This is best achieved by using WBM and drilling sample plugs with water. A standard retort test would also do. With the Swc above the transition zone determined and Sor in the aquifer determined by retort, only in the lower part of the transition zone will the saturations be uncertain.

FIELD EXAMPLES AND DISCUSSION

Case 1; Sw from log matches core

Well 1 is from a gas condensate reservoir and was drilled with OBM. The reservoir formation is sandstone interbedded with shale of Jurassic age from a shallow marine depositional environment. Porosity is constant at approximately 18 % while permeability varies from 10 - 10000 mD. Permeability and water saturation (above the transition zone) are correlated to shaliness or clay content as measured by the gamma ray log. Clay is mainly structural in nature, with little or no diagenetic, and microporous porelining clay is seen. Gas/water drainage experiments (single cell, porous plate at 200 bar hydrostatic confining pressure at ambient T and P) resulted in a saturation exponent, n, of 2.13. The log derived water saturation was calculated using this value for n and laboratory data for m in Archie's equation. This well showed that the laboratory derived Archie parameters gave an accurate estimation of in situ water saturation, Figure 4. This was confirmed by a second well also drilled with OBM. From 3438 to 3441 m, the core porosity and permeability data show the formation to be more heterogeneous on a small scale than that shown by the logs. From 3444 to 3450 m, the logs show greater heterogeneity and poorer formation properties than the core. Whether this is due to technical problems with the log data, or with the depth shift between core and log, the log evaluation, or a combination of these factors has not been determined. In any case these data were excluded from the Sw comparison.

Case 2; Sw from core useless due to high mud invasion.

Well 2 was drilled with WBM in the same field and formation as in case 1. Experimental results of the D-S analysis were presented above as the example of WBM/high invasion. Figure 4 shows that the core derived Sw overestimated water saturation and thus could not be used to verify (or calibrate) the water saturation equation. The differences are significantly larger than that which could be explained by errors in Rw or Rt.

Case 3; Sw from core used to adjust saturation *n*-exponent

Well 3 (OBM) is also from a gas condensate field, but the reservoir formation is a turbiditic sandstone of Paleocene age. Most of the reservoir has a porosity of 25-30 % and permeability between 100 and 1000 mD. A small amount (2-4 wt.%) of diagenetic, microporous, porelining clay (mostly Chlorite and Illite) is present and has a significant impact on the relationship between porosity, permeability and water saturation. Gas/water drainage experiments (single cell, porous plate at 150 bar hydrostatic confining pressure at ambient T and P) resulted in a saturation exponent, n, of 2.04. Well 3 was drilled with tracer added OBM. D-S analysis was performed on core plugs drilled and preserved at well site. Figure 5 shows a comparison between the core and log data. To get the mean value of the water fraction from core and log to match, n had to be changed to 2.28 ($\overline{Sw_{\text{core}} \cdot \Phi_{\text{core}}}$ vs. $\overline{Sw_{\log} \cdot \Phi_{\log}}$ with the log only evaluated at the depths of the core samples). A second well (not shown), also drilled with OBM and with Sw from core, verified this result.

Case 4; Sw from core used to evaluate wettability and laboratory measurement conditions

Well 4 is from the same formation as well 1, but was an oil appraisal well in a separate structure. The discovery well on that structure was also cored and, by the time well 4 was drilled, special core analysis had been performed at various conditions. A set of 3 samples was subjected to two combined USBM-Amott tests to evaluate wettability. The first measurement cycle was performed after cleaning with laboratory oil and simulated formation brine at ambient conditions, the so-called "fresh state". Subsequently the samples were cleaned by displacement with toluene gradually changing to methanol at 70 ^{0}C, before the second USBM-Amott test was performed. Resistivity was measured after centrifuging to Swi in both measurement cycles. Two sets of single cell, porous plate oil/water drainage experiments at 150 bar hydrostatic confining pressure were also performed. The first was performed using refined oil at ambient T, the second with stock tank oil at reservoir T. The Sw vs. resistivity index, RI, results are shown in Figure 6. The interpretation of these results is that there is a high value of *n* approximately equal to 2.90 associated with the more oil-wet state, a water-wet value of approximately 2.13, and an intermediate wetting value of approximately 2.48 which is best predicted by the stock tank oil at reservoir T experiments. Log Sw was calculated using Archie and these 3 values of *n*. These 3 cases are shown in Figure 5 with the Sw from core data. The conclusion is that the intermediate wetting conditions with the corresponding *n* most accurately reflects reservoir conditions and gives the best estimation of reservoir Sw *on average,* but it might be that a variable n should be used (ref. 8). For example, in the interval 3050 to 3060 m, one might argue that the more water-wet condition with n=2.13 should be applied.

Case 5: Low resistivity, thin-bed formation

Both logs and cores have been used to estimate the correct water saturation for a deep thin-bedded formation with complex mineralogy. The formation is partly shallow-marine with both fine-grained and silty tidal influenced lower and middle shoreface sandstones and partly heterolithic sub tidal channel sandstones, Figure 7. Besides the sedimentary facies variation the reservoir quality is controlled by sand quality, quartz cementation, Illite growth, grain coating Chlorite and secondary porosity. The grain coating Chlorite prevents quartz cementation and keeps the porosity as high as 0.20 to 0.25 at a depth of 4000 to 5000 meters. The Sw is high (0.45 to 0.55) in these high porosity and high permeability zones which is due to the high surface area/pore volume ratio generated by grain coating Chlorite. This allows capillary forces to trap water while hydrocarbons flow. Both logs and cores show high Sw. The Chlorite coating thickness increases with temperature from about 2 microns at the upper part of the formation to 7 microns at the lower part. This increase in thickness is also seen from the increase in log Sw with depth. This change in Sw from logs is mainly seen from increase in cementation factor, m, from 2.0 to 2.15 and saturation exponent, n, from 2.2 to 2.5 by depth for the Chlorite coated zones.

Thin-bed analysis based on conventional wireline logs is a problem due to the vertical resolution. To correctly determine the oil in place and dynamic properties of the rock, it is necessary to determine the petrophysical properties on the finest scale. This is because the saturation equations are non-linear and because permeability calculated from log porosity would ignore the tight silty and muddy thin beds. Therefore, the task was to use porosity, permeability and water saturation from core data to get a better vertical resolution than conventional logging tools.

Figure 8 compares the water saturation from logs (Waxman Smits) with cores (D-S and OBM).
Due to grain coating Chlorite, the Sw is about 0.5 for the high porosity zone (5686 to 5693 m). A DST from this zone shows only oil production and does not fit with the high Sw (> 0.7) for three of the core plugs. Closer inspection revealed that these samples had been taken from the thin tight zones of this heterolithic sandstone and are not representative of the average reservoir quality. The core plugs had all been drilled from the end of each core meter length with no regards for lithology. As with sampling for other petrophysical parameters, one has to be aware of consequences of non representative sampling in heterogeneous formations.

For the low permeability or tight zone (5693 to 5696 m), the logs show almost the same Sw (0.55) as the good reservoir zone above. The D-S however shows Sw = 0.75. Since the OWC is only 10 meters lower, the Sw in the almost tight zone has to be higher than the good reservoir zone and close to the values from D-S. To verify the D-S values, some of the tight or low permeability samples were crushed before measuring Sw. Crushed and non crushed samples gave the same high Sw in low permeability or tight sand.

Figure 9 is from another well with OBM where the difference in Sw from logs and cores is mainly due to thin beds problems where conventional logs show average values and cores show point values. The lower part (5226 to 5236 m) has another depositional environment with thicker homogeneous sand zones (1-2 meters) which gives a better correlation between logs and cores.

Case 6; Verification of logs in high microporosity sandstone

A Late Paleocene/Early Eocene sandstone oil reservoir in the North Sea is characterised by porosities ranging from 25 to 35 % and permeabilities ranging from <1 to 1000 mD. Petrographic analyses revealed a fine to very fine grained well sorted sand with a complex mineralogy. Quartz is the dominant mineral, but large volumes of glauconite (18-38 vol%) in addition to abundant Chlorite (4 to 26 wt%) is causing this reservoir to maintain very special petrophysical characteristics. The microporosity (> 50%) associated with the micro-porous glauconite and dispersed pore-filling and pore-lining chloritic clay causes a poor correlation between porosity and permeability. The water-wet micro-porosity is also causing high immobile water saturations, resulting in low electric resistivities (1-5 ohm-m) of the pay zones. Irreducible water saturations vary between 27 and 55% of the total core porosity.

The entire gross reservoir interval of two wells were cored. The first well was cored with a WBM (KCl) with no tracer added. The second well was cored using a low invasion core bit and a tracer-doped "synthetic" OBM for the purpose of providing core water saturation data for log calibration.

Significant mud filtrate invasion between coring and electric wireline logging combined with mineralogical effects from the iron bearing minerals resulted in large uncertainties with respect to the "true" formation resistivity and hence the water/hydrocarbon saturation. This was demonstrated in the first well by the LWD resistivity log reading significantly higher values than the later wireline resistivity log. There was no invasion of water from the mud in the second well (OBM). The D-S analyses revealed that "correct" results regarding saturations were obtained from the LWD resistivity log. If tracer had been used in the first well, much of the early uncertainty in saturation and STOOIP could have been avoided.

CONCLUSIONS

1. Sw determined from cores is highly valuable in petrophysical evaluation and should be considered for all cored intervals of exploration and development wells.
2. Planning of the coring and analysis project is important. The oil company's drilling and reservoir engineering department, the coring company and the core analysis laboratory should be involved. Coring equipment, mud and parameters must be targeted at low invasion, in addition to core recovery and quality. Tripping rates should be reduced near the surface to reduce effect of gas expansion
3. A tracer must be added when coring with water based mud and Tritium is preferred. Plugs for Sw determination must be drilled at well site.
4. Tracer for the water phase is generally not needed when coring with oil based mud. Plugs can be drilled in the core laboratory. Precautions should be taken in extreme cases of formation properties, drilling parameters and new mud types.
5. Core and log Sw are generally in good agreement unless the WBM correction is too high. Both Swc from cores and m + n from special core analysis should be used in the log interpretation. Consider to change resistivity parameters if they do not agree with quality Swc from core.
6. In heterolithic and laminated formations the point measurements of the core analysis and the lower resolution logs represent measurements at different scales. The location of each plug should be taken into account in the interpretation.

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Table 1 **Example of laboratory saturation data from WBM well with little filtrate invasion**

DEPTH Core RKB meters	SW CORR. Invasion corr. Amb. cond % Pore Vol	SW D&S Measured by D-S % Pore Vol	INVASION Mud cont. in D-S water % of water	POROSITY He-exp. Amb. cond %	PERM HOR. Klh 1" conv. plug mD	PERM VERT Klv 1.5" D-S plug mD	D&S PLUG Drilled Offshore (O) Laboratory (L)	Calc. mud-invasion %Porevol
4649.10	10.76	12.14	11.22	19.05	0.02		L	1.4
4650.15	15.98	17.71	9.68	15.65	70.3		L	1.7
4651.00	4.61	5.24	11.83	22.19	36.7		L	0.6
4652.12	6.13	6.40	4.03	21.66	935		L	0.3
4653.10	7.95	8.76	9.13	17.41	686		L	0.8
4653.85	4.75	5.63	15.44	21.10	467		L	0.9
4655.00	3.61	4.18	13.25	20.13	919		L	0.6
4656.00	5.86	7.24	18.84	19.48	975		L	1.4
4656.87	32.33	33.77	4.21	10.57	832		L	1.4
4657.87	18.71	19.58	4.35	15.78	27.6		L	0.9
4658.87	14.88	15.77	5.56	17.81	27.7		L	0.9
4659.90	32.06	35.02	8.34	10.42	25.2		L	2.9

Table 2 **Example of laboratory saturation data from WBM well with high filtrate invasion**

DEPTH Core RKB meters	SW CORR. Invasion corr. Amb. cond % Pore Vol	SW D&S Measured by D-S % Pore Vol	INVASION Mud cont. in D-S water % of water	POROSITY He-exp. Amb. cond %	PERM HOR. Klh 1" conv. plug mD	PERM VERT Klv 1.5" D-S plug mD	D&S PLUG Drilled Offshore (O) Laboratory (L)	Calc. mud-invasion %Porevol
3593.00	10.9	27.4	60.37	20.8	1890	2100	L	16.5
3595.00	9.0	30.6	70.5	16.6	712	635	L	21.6
3597.00	10.6	25.4	58.21	18.4	3070	2320	L	14.8
3599.00	10.0	29.6	66.34	19.4	4690	4470	L	19.7
3601.00	9.0	28.4	68.22	19.8	6030	7090	L	19.4
3603.00	11.3	33.6	66.51	19.1	7190	3090	L	22.4
3605.00	7.1	38.8	81.62	18.9	5330	3110	L	31.7
3606.00	7.5	33.0	77.19	18.3	15500	5450.0	L	25.5
3607.00	7.2	37.5	80.87	18.7	22500	5330.0	L	30.3
3609.00	7.5	37.3	79.98	19.4	7020	4990.0	L	29.8
3611.00	7.9	38.6	79.62	18.2	34700	670.0	L	30.7
3613.00	25.9	32.4	20.18	21.4	45.6	47.9	L	6.5

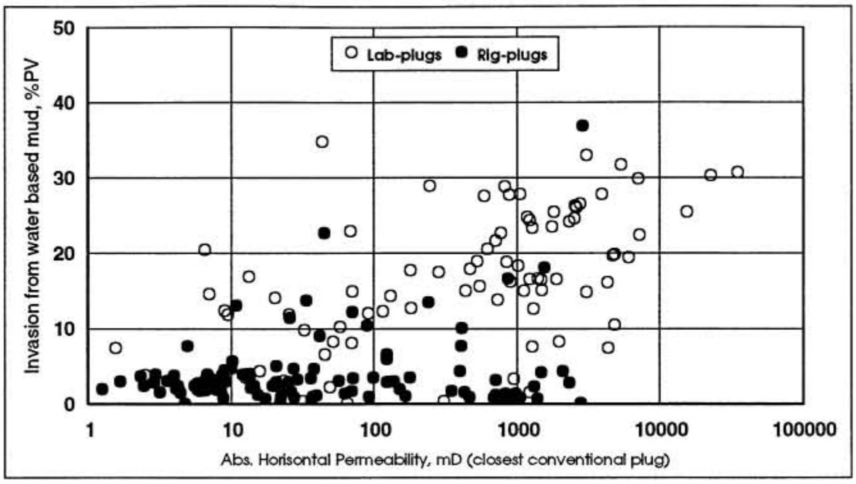

Figure 1. Mud invasion from WBM versus permeability. Several wells.
Comparison of plugs drilled at rig site with plugs drilled in laboratory 5-10 days later.

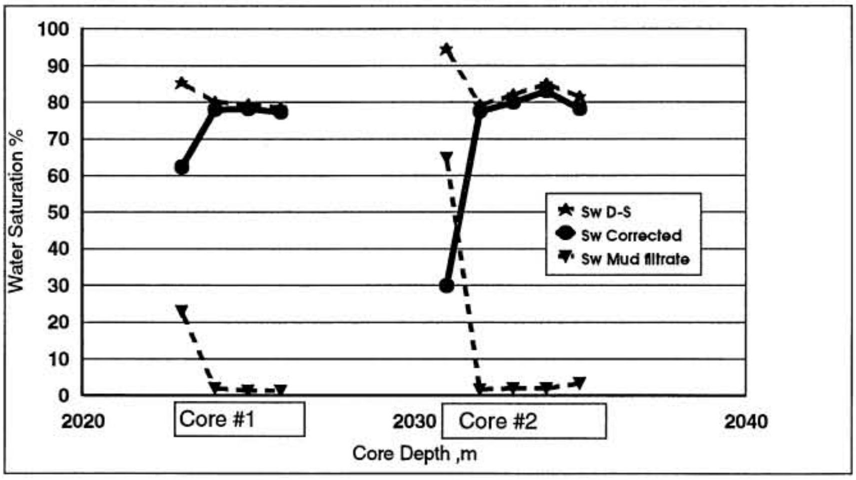

Figure 2 Mud invasion from WBM into water saturated formation.

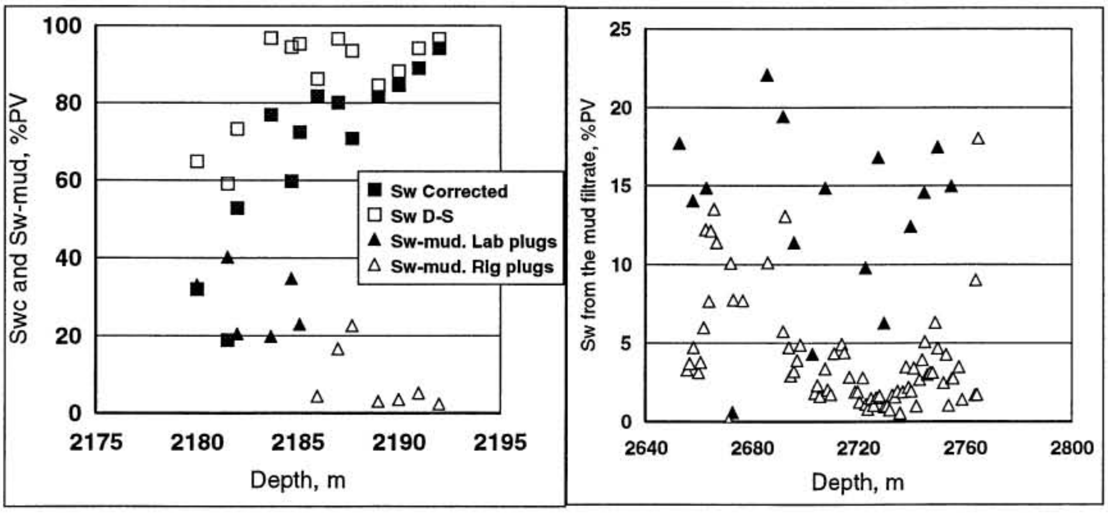

Figure 3 Examples of increasing mud invasion from WBM into centre of core with time from coring.
Plugs drilled immediately after core retrival and in the core laboratory approx. 1 week later

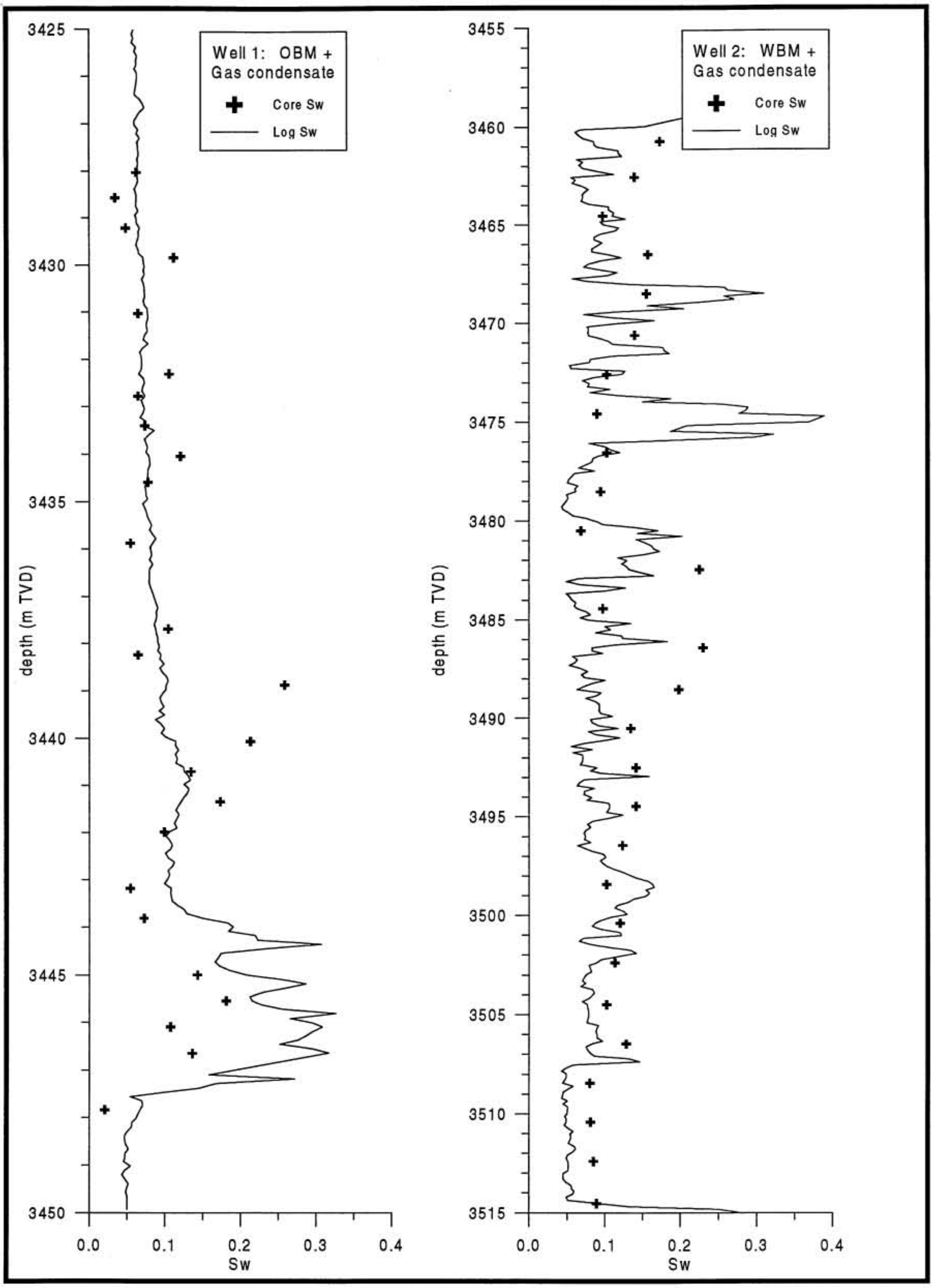

Figure 4. Comparison of log derived water saturation with Dean-Stark measurements on core from two wells from the same reservoir, one drilled with OBM, the other with WBM.

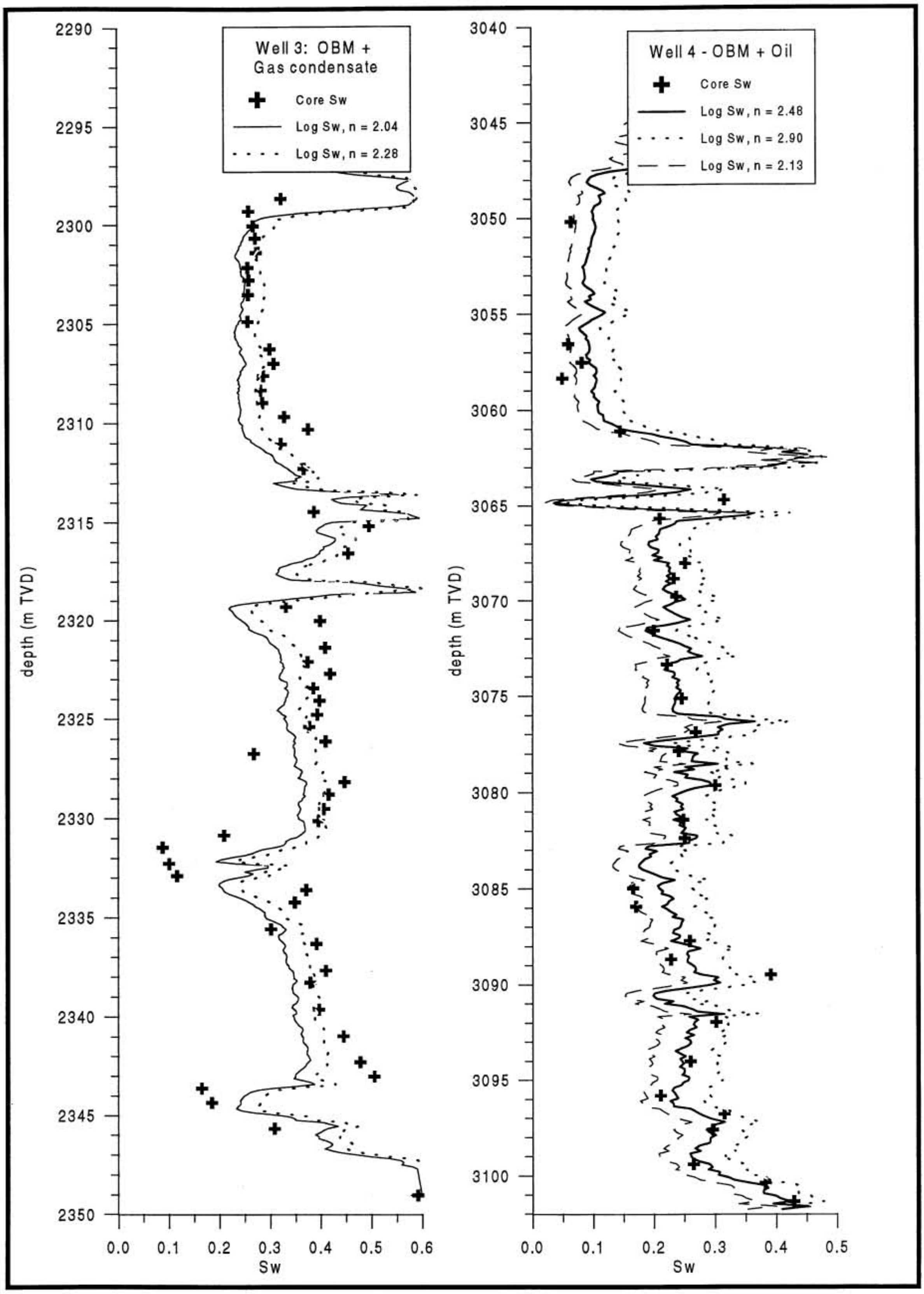

Figure 5. Comparison of log derived water saturation with Dean-Stark measurements on core, well 3 and 4.

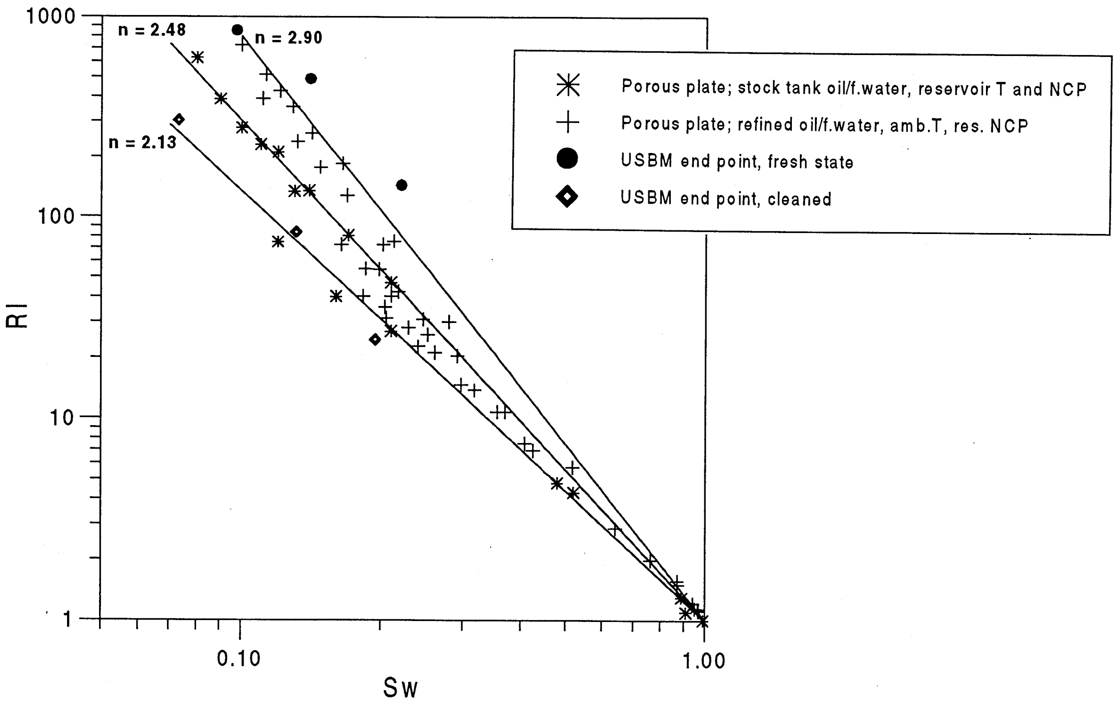

Figure 6. RI vs. Sw for various laboratory conditions, case 4.

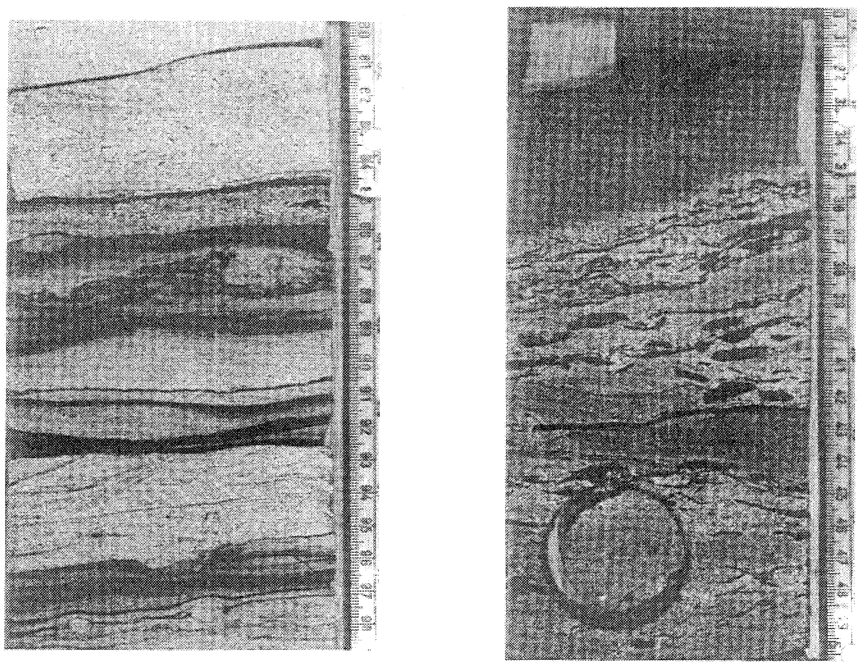

Figure 7. Core photos showing sand-rich and mud-rich layers interbedded at the centimeter scale from the heterolithic tidal reservoir

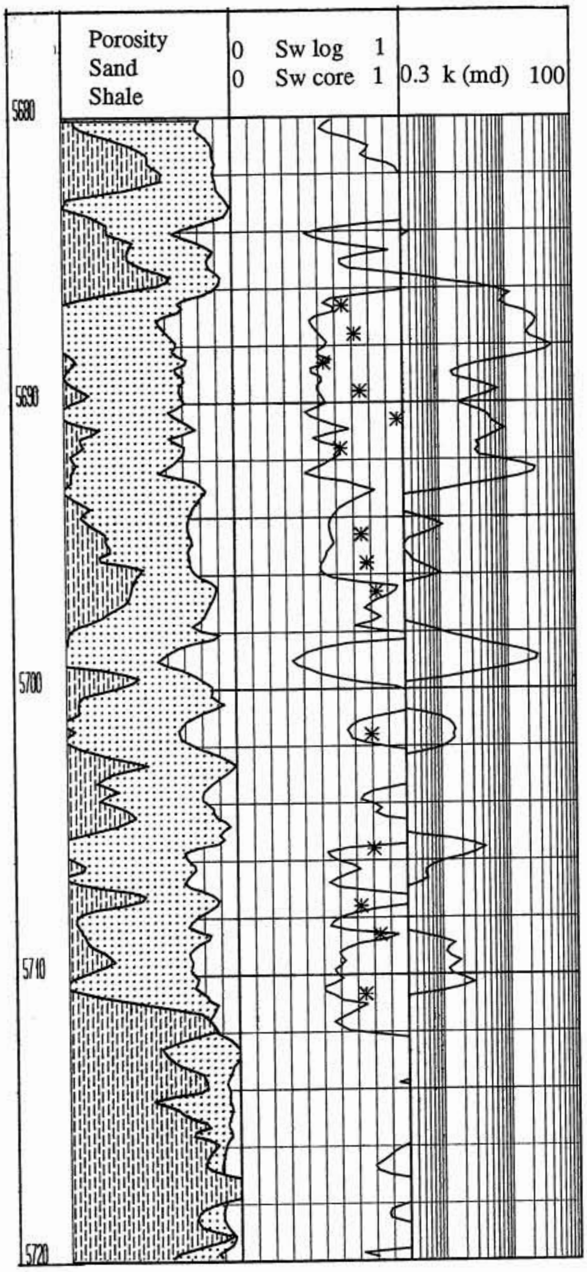

Fig. 8. Lithology, porosity, saturation and permeability from a heterolitich formation. Water saturation both from logs and cores (D→S)

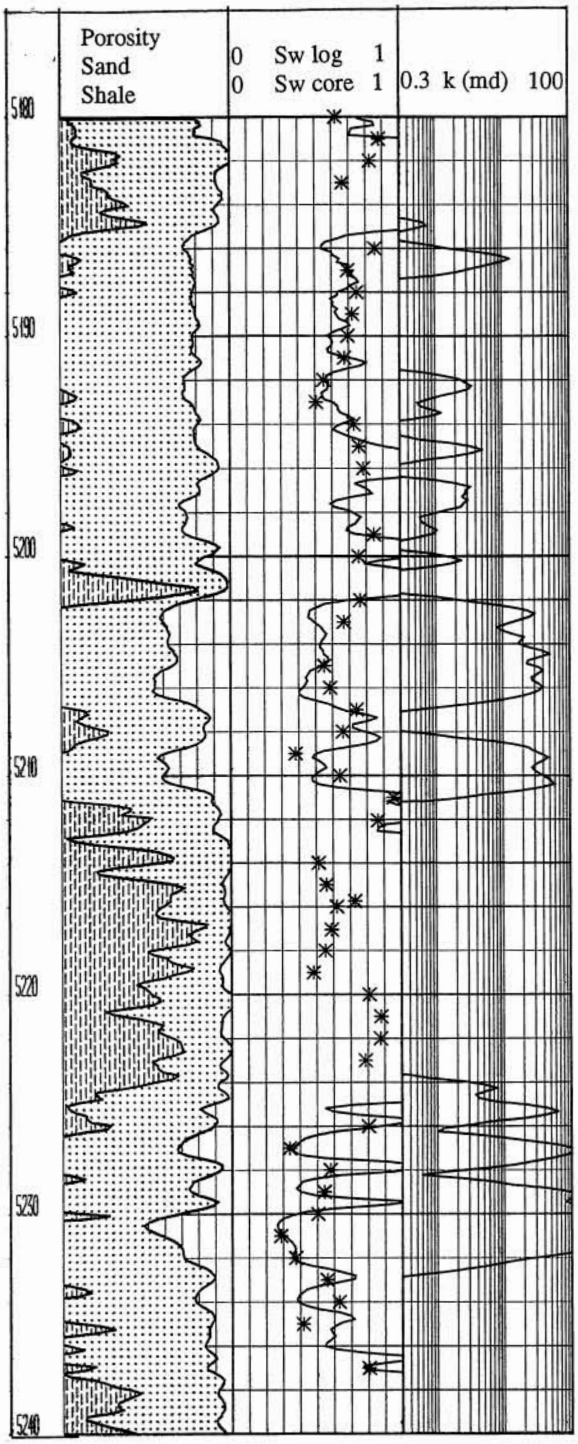

Fig. 9. Lithology, porosity, saturation and permeability from a heterolitich formation. Water saturation both from logs and cores (D→S)