5
SELF-POTENTIAL
OR SP LOGS

5.1 Generalities

The log

The SP log is a measurement of the natural potential differences or self-potentials between an electrode in the borehole and a reference electrode at the surface: no artificial currents are applied (Figure 5.2). (The currents were actually called 'potentiels spontanés', or 'spontaneous potentials', by Conrad Schlumberger and H.G. Doll who discovered them.) They originate from the electrical disequilibrium created by connecting formations vertically (in the electrical sense) when in nature they are isolated.

Principal uses

The principal uses of the SP log are to calculate formation-water resistivity and to indicate permeability. It can also be used to estimate shale volume, to indicate facies and, in some cases, for correlation (Table 5.1, Figure 5.1).

5.2 Principles of measurement

Three factors are necessary to provoke an SP current: a conductive fluid in the borehole; a porous and permeable bed surrounded by an impermeable formation; and a difference in salinity (or pressure) between the borehole fluid and the formation fluid. In oilfield wells, the two fluids concerned are the mud filtrate and (usually), formation water.

SP currents are created, when two solutions of different salinity concentrations are in contact, by two principal electrochemical effects; *diffusion or liquid junction potential and shale potential* (Figure 5.3). The diffusion potential (or liquid junction potential) arises when
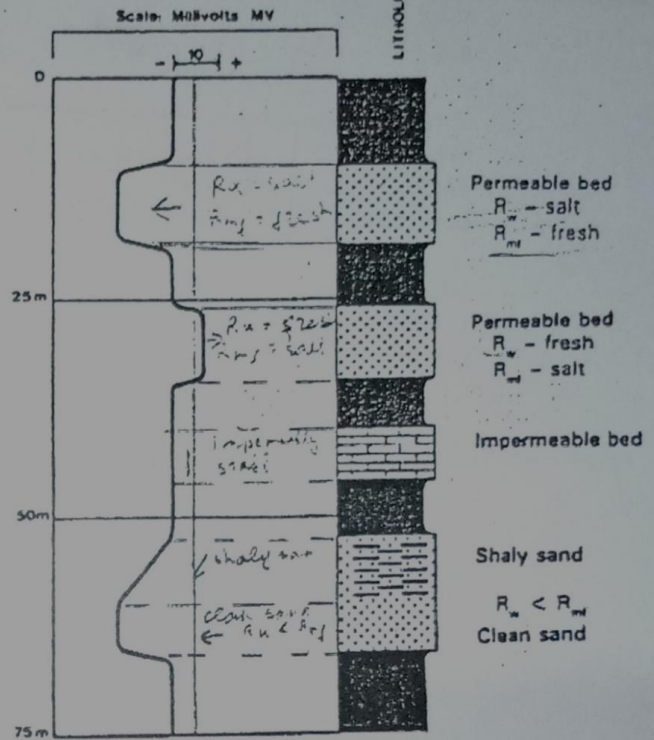

Figure 5.1 The SP log: some typical responses. The SP log shows variations in natural potentials. R_w = formation-water resistivity; R_{mf} = mud filtrate resistivity.

solutions of differing salinity are in contact through a porous medium. Sodium chloride, NaCl, is the most common cause of oilfield salinity, so that it is effectively two solutions of sodium chloride of different salinities that come into contact. Through the porous medium,

Table 5.1 The principal uses of the SP log.

	Discipline	Used for	Knowing
Quantitative	Petrophysics	Formation-water resistivity	Mud filtrate resistivity and formation temperature
		Shale volume	SSP and shale line
Qualitative	Petrophysics	To indicate permeability	Shale line
	Geology	Facies (shaliness)	Clay/Grain size relationships
		Correlation	

fluid content
Free gas or light (compressible) oil will tend to sharply decrease the compressional wave velocity in sands (Figure 8.10), especially loosely consolidated sands, but there will be little effect on shear wave velocity. This fluid content effect is noted in Poisson's ratio (the ratio of lateral strain to longitudinal strain which is derived from the P and S wave velocities). An example from a North Sea, Palaeocene sand-shale sequence (Bunch and Dromgoole, 1995), shows that shale, water sands and gas sands can be reasonably differentiated using Poisson's ratio but no such separation can be made based on acoustic impedance (i.e. compressional wave × density) (Figure 8.37). Observations such as these can be used to refine seismic analysis.
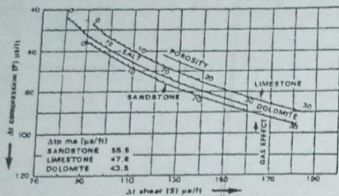

Figure 8.36 Graph of compressional against shear slowness derived from the array sonic. The graph shows sandstone, limestone and dolomite fields over porosity ranges to 30%. (From CGG document).
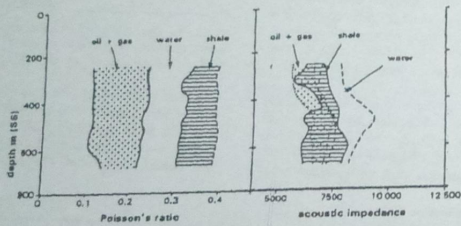

Figure 8.37 Example of the use of Poisson's ratio. Shale, water-bearing sandstone and gas sands showing markedly different values of Poisson's ratio (left) but similar acoustic impedance; (right) North Sea Palaeocene (modified from Bunch and Dromgoole, 1995).

9
THE DENSITY AND PHOTOELECTRIC FACTOR LOGS

9.1 The density log, generalities

The log
The density log is a continuous record of a formation's *bulk density* (Figure 9.1). This is the overall density of a rock including solid matrix and the fluid enclosed in the pores. Geologically, bulk density is a function of the density of the minerals forming a rock (i.e. matrix) and the volume of free fluids which it encloses (i.e. porosity). For example, a sandstone with no porosity will have a bulk density of 2.65g/cm^3, the density of pure quartz. At 10% porosity the bulk density is only 2.49g/cm^3, being the sum of 90% quartz grains (density 2.65g/cm^3) and 10% water (density 1.0g/cm^3).

Principal uses
Quantitatively, the density log is used to calculate porosity and indirectly, hydrocarbon density. It is also used to calculate acoustic impedance. Qualitatively, it is a useful lithology indicator, can be used to identify certain minerals, can help to assess source rock organic matter content (even quantitatively) and may help to identify overpressure and fracture porosity (Table 9.1).
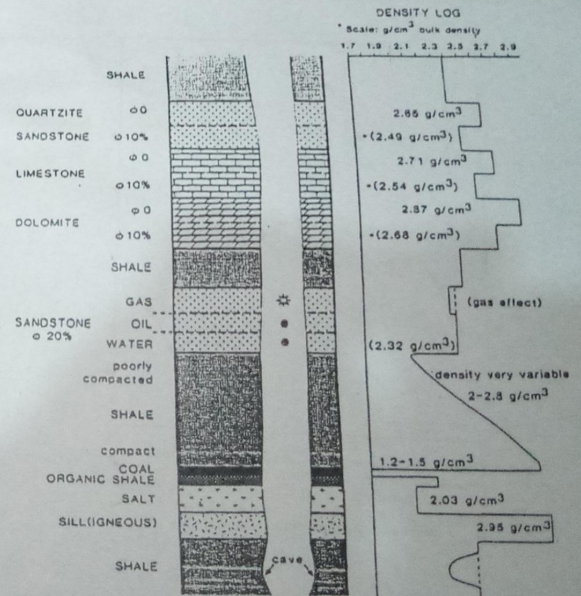

Figure 9.1 The density log: some typical responses. The density log shows *bulk density*. *Density and porosity with fresh formation-water density 1.0g/cm^3 (cf. Figure 10.1, which is on a compatible scale of neutron porosity).

Table 9.1 The principal uses of the density log.

	Discipline	Used for	Knowing
Quantitative	Petrophysics	Porosity	Matrix density
			Fluid density
	Seismic	Acoustic impedance	(Use raw log)
Qualitative and semi-quantitative	Geology	General Lithology	Combined with neutron*
		Shale textural changes	Average trends
		Mineral identification	Mineral densities
	Reservoir geology	Overpressure identification	Average trends
		Fracture recognition	Sonic porosities
	Geochemistry	Source rock evaluation	Density – O.M. calibration

*using density log combined with neutron log on compatible scale

9.2 Principles of measurement

The logging technique of the density tool is to subject the formation to a bombardment of medium-high energy (0.2–2.0 MeV) collimated (focused) gamma rays and to measure their attenuation between the tool source and detectors. Such is the physical relationship that the attenuation (Compton scattering, *see* Section 7.2) is a function of the number of electrons that the formation contains – its electron density (electrons/cm^3) – which in turn is very closely related to its common density (g/cm^3) (Table 9.2). In dense formations, Compton scattering attenuation is extreme and few detectable gamma rays reach the tool's detectors, while in a lesser density the number is much higher. The change in counts with change in density is exponential over the average logging density range from about 2.0–3.0 g/cm^3 (Figure 9.2). Detector counts in modern tools are converted directly to bulk density for the log printout (Figure 9.5). However, although electron density, as detected by the tool, and real density are almost identical, there are differences when water (hydrogen) is involved. For this reason, the actual values presented on the density log are transformed to give actual values of calcite (2.71g/cm^3) and pure water (1.00g/cm^3) (Table 9.2). (There are still slight differences between log density and real density, especially when chlorine is involved.)

9.3 Tools

The standard density tools have a collimated gamma ray source (usually radiocaesium which emits gamma rays at 662 keV, but radiocobalt is also used) and two detectors (near and far) which allow compensation for borehole effects when their readings are combined and compared in calculated ratios. The near detector response is essentially due to borehole influences which, when removed from the
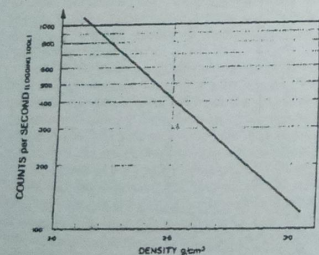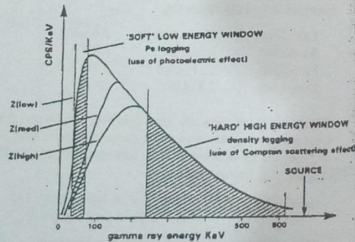

Figure 9.2 Correlation between the density-tool radiation count (counts per second) and bulk density. A high density gives a low count. (Re-drawn from Desbrandes, 1968).

Figure 9.3 Density and lithodensity (photoelectric) logging in relation to gamma ray energy. Density logging uses the high energy-regions where Compton scattering occurs. Photoelectric logging uses the low energy region where the photoelectric effect is dominant. CPS = counts per second. KeV – kilo electron volts. Z = atomic number. (Modified from Ellis, 1987).

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Table 9.2 Density, electron density and tool given density for some common compounds (from Schlumberger, 1989a).

Compound	Formula	Actual density ρ_b, g/cm^3	Tool density based on electron density (pe), g/cm^3	*Density given on log g/cm^3
Quartz	SiO$_2$	2.654	2.650	2.648
Calcite	CaCO$_3$	2.710	2.708	2.710
Dolomite	CaCO$_3$MgCO$_3$	2.850	2.863	2.850
Halite	NaCl	2.165	2.074	2.032
Gypsum	CaSO$_4$2H$_2$O	2.320	2.372	2.351
Anhydrite	CaSO$_4$	2.960	2.957	2.977
Sylvite	KCl	1.984	1.916	1.863
Coal bituminous		1.200	1.272	1.173
		1.500	1.590	1.514
Coal anthracite		1.400	1.442	1.355
		1.800	1.852	1.796
Fresh water	H$_2$O	1.000	1.110	1.000
Salt water	200,000 ppm	1.146	1.273	1.135
Oil	n(CH$_2$)	0.850	0.970	0.850
Methane	CH$_4$	0.000677	0.00084	
Gas	C$_{1.1}$H$_{4.2}$	0.000773	0.00096	

*Density given on log = 1.0704 (pe) – 0.1883

Table 9.3 Modern density tools.

1. Density measurement

Name	Symbol	Company
Formation Density		
Compensated	FDC	Schlumberger
Compensated Densilog	CDL	Western Atlas, Halliburton
Compensated Density	CDS	BPB

2. Density and Photoelectric measurement

Name	Symbol	Company
Litho-Density Tool	LDT	Schlumberger
Compensated Z-Density	ZDL	Western Atlas
Photoelectric Density	PDS	BPB
Spectral Density Tool	HSDL	Halliburton

far detector response enhance the formation effects (Figure 9.6). The most recent density tools (Table 9.3) use more efficient scintillation detectors which separate high (hard) and low (soft) gamma ray energy levels (Figure 9.3). This allows a better evaluation of borehole effects, so providing a more accurate density measurement as well as the additional photoelectric factor value (Section 9.7). Source and detectors are mounted on a plough-shaped pad which is pressed hard against the borehole wall during logging (Figure 9.4). Density-log readings therefore refer to only one sector on the borehole wall.
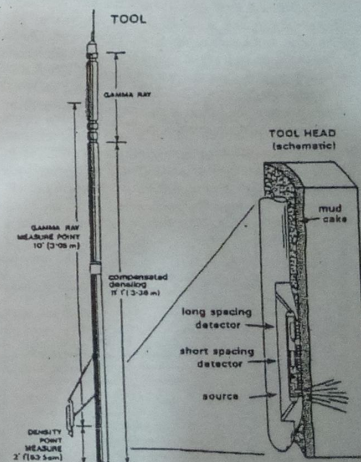

Figure 9.4 A density tool (Densilog from Atlas Wireline) and a tool head (modified from Dresser Atlas, 1982 and Ellis, 1987).
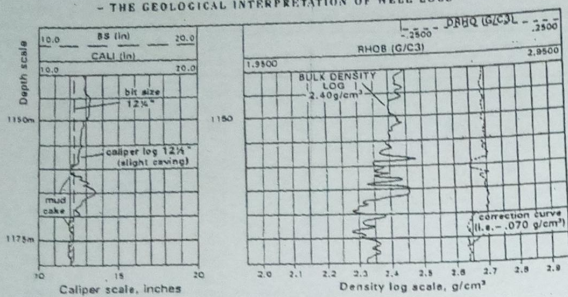
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Figure 9.5 Typical heading of a density log. The density log is over tracks 2 and 3: the scale is in g/cm³. Any mud weight correction is shown in log form (dashed) and is automatically applied. It is based, in this example, on a barite mud containing 272ppm barium and with a density of 1.84g/cm³.

Log presentation, scales and units

The density log is normally plotted on a linear scale of bulk density (Figure 9.5). The log is run across tracks 2 and 3, most often with a scale between 1.95 and 2.95 g/cm³. The main log is accompanied by a curve indicating the borehole and mud-cake corrections that have been automatically applied. A record of cable tension may also be included, as the density tool tends to stick in poor holes.

The tool is run typically as a density-neutron combination along with a gamma ray tool and a caliper, e.g. CDL-GR-N (Western Atlas), FDC-CNL-GR or LDT-CNL-NGT (Schlumberger). The caliper is an essential accompaniment to the density log for reasons of quality control.
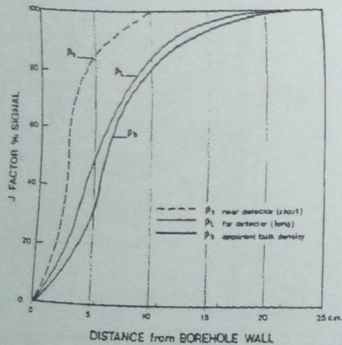

Figure 9.6 The depth of investigation of the density tool is very shallow. The graphs show experimental results for a 35% porosity, water-filled sand. (Re-drawn from Sherman and Locke, 1975).

9.4 Log characteristics

Depth of investigation and bed resolution

Research into the density tool's characteristics shows that its depth of investigation is very shallow. Figure 9.6 shows that 90% of the original Schlumberger FDC response probably originates from 13cm (5in) or less from the tool. These are experimental results using a sand with 35% porosity (Sherman and Locke, 1975). In normal logging, the investigation depth will probably be even less, especially for the more modern tools, around 10cm (4in) for average densities. Consequently the density tool is likely to be much affected by hole conditions. Moreover, in porous zones where the tool has its principal petrophysical use, it will be measuring the invaded zone. There is little chance of it detecting fluids, notably liquid hydrocarbons, in place.

While the depth of investigation of the density tool is small, the bed resolution is good. At average logging speeds (about 400m/h, 1300ft/h), true densities can be read in beds down to about 60cm (2ft). At lower logging speeds, higher sampling rates and selective processing, it may be possible to resolve beds down to 15cm (6") (Flaum *et al.*, 1987). Partial reaction from the density tool may be caused by very thin beds, especially if they have a very high or very low density. Calcareous nodules 5-10cm thick, for example, are seen as peaks on the density log.

Good bed resolution renders the density log useful for drawing bed boundaries.

Unwanted logging effects

The most frequently encountered unwanted logging effects are shown in Table 9.4. The shallow depth of investigation of the density tool makes it very susceptible to hole conditions, despite compensation and automatic corrections. The density log should be interpreted along with its corresponding caliper log.

Table 9.4 Unwanted environmental effects – density log.

Factor	Effect on log	Severity*
Caved or rough hole	Decrease in formation density to approach a drilling mud density value	Frequent
Barite in the drilling mud	Automatically corrected in the tool– when mud-cake is thick, gives the cake density	(Rectified)

*When the effect makes the log reading unusable. Ratings: frequent, common, present, rare.
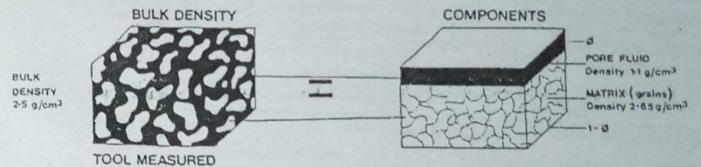

Figure 9.7 Tool measured bulk density and a visualization of the derivation of the porosity component. The figures are for a sandstone with 10% porosity.

9.5 Quantitative uses

Porosity calculation

The density log is used to calculate porosity and it may also, with difficulty, be used to calculate hydrocarbon density. To calculate porosity from log-derived bulk density it is necessary to know the density of all the individual materials involved. The density tool sees global (bulk) density, the density both of the grains forming the rock and of the fluids enclosed in the interstitial pores) (Figure 9.7). As an example, if the tool measures a bulk density of 2.5g/cm³ in a salt-water-bearing formation (fluid density 1.1g/cm³ [as seen by the tool]) we can interpret any of the following:

Lithology	Grain density	Porosity
Sandstone	2.65g/cm³	10%
Limestone	2.71g/cm³	13%
Dolomite	2.87g/cm³	21%

Of course, if we know the grain (matrix) density and the fluid density we can solve the equation that gives porosity from the summation of fluid and matrix components (Figure 9.7). For example,

bulk density (ρ_b) = porosity (ϕ) × fluid density (ρ_f)
    + $(1 - \phi)$ × matrix density (ρ_{ma})

When solved for porosity this equation becomes:

$$\text{porosity } \phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

where ρ_{ma} = matrix (or grain) density, ρ_f = fluid density and ρ_b = bulk density (as measured by the tool and hence includes porosity and grain density).
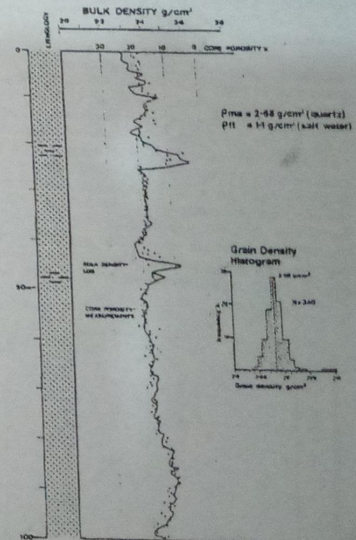

Figure 9.8 Close correspondence between the bulk density log and core-measured porosity in an orthoquartzite. The bulk density can be converted to porosity using a matrix density of 2.68g/cm³, as indicated by the inset histogram.
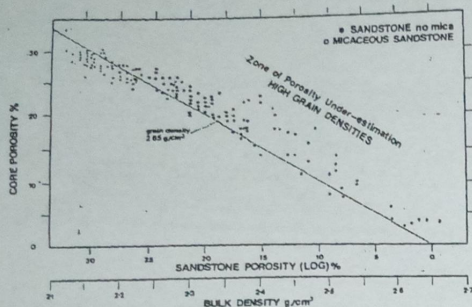
Figure 9.9 The effect of mica on porosity values derived from the bulk density log. For the graph a matrix density of 2.65g/cm³ was used (giving the diagonal line). For the micaceous sands, core-measured porosities are consistently higher than those given by the log, because the grain density is too low at 2.65g/cm³. Mica has densities up to 3.10g/cm³. (Re-drawn from Hodson, 1975).

The relationship between the bulk density (as measured by the tool) and porosity can be extremely close when the grain density remains constant (Patchett and Coalson, 1979). The example shows a reservoir of orthoquartzite composition and a reasonably constant grain density of 2.68g/cm³ (Figure 9.8). The porosity derived from the bulk density log in this example corresponds well to the core porosity when a matrix density of 2.68g/cm³ and tool-registered fluid density of 1.1g/cm³ are applied.

If constant grain-density figures are applied to a formation and the grain density is not constant, the porosity calculated is inaccurate. An error in grain density of 0.01g/cm³ has been calculated to cause an error of 0.5% (Granberry et al., 1968). Such errors can occur in the North Sea Jurassic sands, where up to 30% mica can increase the average grain density to 2.84g/cm³ (mica density is about 2.76–3.1 g/cm³). When too low a grain density is used, the porosity is underestimated by the density log (Figure 9.9).

Erroneous porosities may also be calculated when the fluid density changes. This is the case when a rock is saturated with gaseous hydrocarbons. As shown above, the porosity equation is furnished with a grain density and a fluid density. The latter is 1.0g/cm³ for fresh water and 1.1g/cm³ for salt water (but may vary with temperature). In the presence of gas (typical density 0.0007g/cm³) the fluid density drops dramatically. As the example shows, the density log gives too high a porosity (Figure 9.10). If the porosity (and water saturation) can be calculated by other means, the density log can be used to calculate the hydrocarbon density.

When oil is present, the porosity given by the density log is essentially correct. This is because the density tool
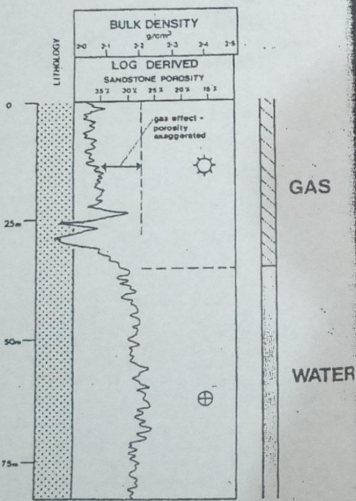

Figure 9.10 The effect of gas on the density log. In this example the gas zone reads about 35% porosity: it should read 27% porosity.

investigates the flushed zone (see 'Depth of investigation', Section 9.4) where only a small volume of oil remains. Moreover, the density of oil is quite close to that of water (0.7g/cm³ vs. 1.0g/cm³). Gas, however, is more mobile and frequently occurs in the flushed zone where, because of the large density difference with water, it has the effect of diminishing the bulk density as described above.

Acoustic impedance

The density log is used in conjunction with the sonic log to calculate acoustic impedance. The subject is briefly described in Chapter 8 (see 'Seismic applications of the sonic log').

9.6 Qualitative uses

The density tool gives a continuous log of the formation's bulk density and it needs no interpretation as the character is given directly. The qualitative use of this log therefore depends on the geological significance of the density of a formation.

Lithology identification

The densities of the more common lithologies are rarely diagnostic since there is too much overlap and too much spread caused by differences in composition and texture. Shales, for example, may have densities ranging from 1.8g/cm³ to 2.7g/cm³: the density difference between a plastic clay and a compacted shale (Table 9.5). Overall, oilfield densities generally measure between 2.0g/cm³ and 3.0g/cm³, the common lithologies spanning the whole of this range (Figure 9.11).

Table 9.5 Densities of common lithologies (see also Figure 9.11).

Lithology	Range (g/cm³)	Matrix (g/cm³)
Clays–shales	1.8–2.75	Varies (av. 2.65–2.7)
Sandstones	1.9–2.65	2.65
Limestones	2.2–2.71	2.71
Dolomites	2.3–2.87	2.87

Although the density log is itself a poor indicator of lithology, combined with the neutron log it becomes excellent. In fact the neutron-density log combination is probably the best qualitative indicator of general lithology especially in the presence of a valid PEF curve. The subject is described in Chapter 10 (see 'Neutron-density combination').

The density log in shales: compaction, age and composition

The compaction of shales with burial is a well-known phenomenon and it can be followed on the density log. Shale compaction involves a series of textural and compositional changes, resulting in a progressive increase in density (e.g. Burst, 1969). For example shallow, uncompacted clays have densities around 2.0g/cm³, while at depth, this figure commonly rises to 2.6g/cm³.

Changes due to compaction are gradual and, when seen in one well, occur over a considerable thickness of sediment (Figure 9.12). To see clay compaction changes, unless the shale series is very homogeneous, the density log should be re-plotted at a small vertical scale (say 1:5000). This method allows clay compaction to be examined even in shale-sand or shale-lime sequences.

Shale age and unconformities

Although it is by no means diagnostic, shale density is often indicative of age. In general, older shales are more dense. Palaeozoic clays are rare, as are Tertiary shales. The increase in shale density during compaction, although essentially due to a decrease in porosity, is accompanied by irreversible diagenetic changes (Shaw, 1980). Compaction trends therefore become 'fossilized'. This means that in the subsurface, a change in compaction trends will indicate a change in age, in other words an unconformity (Figure 9.13). Beyond this, if general compaction curves for a region can be established, the maximum depth of burial of a formation can be estimated. The methodology is similar to that described using the sonic log (see 'Compaction', Chapter 8). However, for compaction studies the density log must be used carefully.
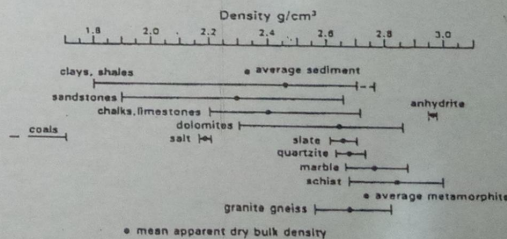

Figure 9.11 Density ranges of some common lithologics. Note the similar ranges of clay/shale, sandstone and limestone (modified from Jackson and Talbot, 1986).
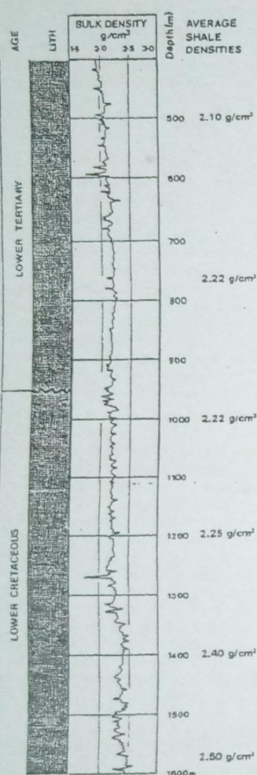
Figure 9.12 Shale compaction with depth seen on a bulk density log plotted at a compressed (small) vertical scale.

It is very responsive to local lithological variations and a usable average is often hard to obtain.

Shale composition

Shale density changes due to compaction are gradual, while small-order, local variations are more likely due to changes in shale composition. For example, an increase in carbonate content is generally accompanied by an increase in shale density (Figure 9.14). The increase in density is even more marked when iron carbonate
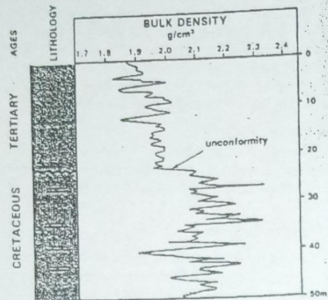

Figure 9.13 Tertiary shales unconformably overlying dipping, eroded, Cretaceous shales. The abrupt change in density marks the unconformity.

(siderite) is involved (density when pure, $3.89g/cm^3$). When organic matter is present, the reverse occurs and the density diminishes, organic matter having a very low density (of around $1.2g/cm^3$; Figure 9.22). This relationship may be quantified (see 'Source rock evaluation' below).

The density log in sandstones – composition and diagenesis

Bulk density variations in sandstone generally indicate porosity changes. However, as explained above, this is not true when there are changes in grain density. Pure quartz sands are considered to have a grain density of $2.65g/cm^3$, but in reality such sands are rare. Overall grain density will change depending on the non-quartz constituents. Sands are commonly mixed with feldspars (density $2.52–2.63g/cm^3$), micas ($2.65–3.1g/cm^3$) lignite fragments ($0.5–1.8g/cm^3$) and rock fragments (variable density). Heavy minerals may also be a constituent ($2.7–5.0g/cm^3$). The well-known mica sands of the North Sea Jurassic reservoirs (as already discussed) contain up to 30% muscovite (Figure 9.9). The density of muscovite ($2.76–3.10g/cm^3$) increases the average grain density from $2.65g/cm^3$ to c. $2.82g/cm^3$ and it varies with the mica content (Figure 9.15). In sands without shale, therefore, grain density can give some idea of sand composition.

Changes in grain density in sands are generally gradual and of a moderate order. Abrupt changes, especially in otherwise homogeneous beds, often indicate diagenetic or secondary changes. The example shows a sand with zones of secondary carbonate cement (Figure 9.16). In cores these zones are shown to have very abrupt limits. A similar phenomenon may also occur with secondary pyrite cement.

Mineral identification

Density becomes a criterion for lithological identification when it is either abnormally high or abnormally low (the average for sedimentary rocks in oil wells being about
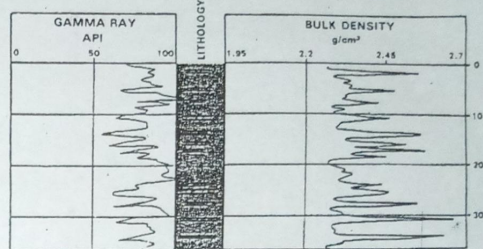
Figure 9.14 Thin, carbonate/siderite cemented horizons in shale. The intervals may be thin continuous bands or irregular, nodular horizons.
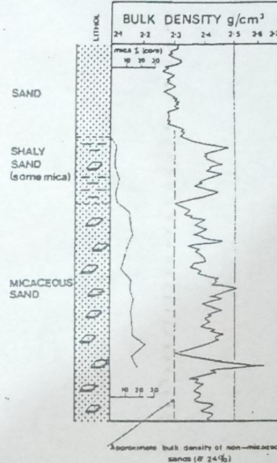

Figure 9.15 The effect of muscovite (grain density 2.76 – 3.1 g/cm^3) on the bulk density log in micaceous sands. The increase in density below 15m is due to the mica content. The percentage of mica indicated is based on thin-section analysis of core material.
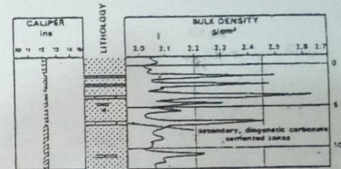

Figure 9.16 Secondary calcareous cementation in sandstone. The density log shows thin, cemented intervals which have little or no porosity while the reservoir generally has 30% – 35% porosity.

Table 9.6 Diagnostic mineral and lithological densities (from Serra, 1972, 1979; Gearhart, 1983; Dresser Atlas, 1983).

		(g/cm^3)
Low	Lignite	0.50–1.50
	Coal	1.15–1.70
	Anthracite	1.15–1.70
	Organic shale	1.80–2.40
High	Pyrite	4.80–5.17
	Siderite	3.0–3.89
	Basalt	2.70–3.20
	Gneiss	2.60–3.04

$2.3g/cm^3$). Coals, for example, are identified by very low densities, between $1.2g/cm^3$ and $1.8g/cm^3$, and pyrite, conversely, by very high densities, between $4.8g/cm^3$ and $5.17g/cm^3$. The extreme values for these minerals may not be reached under natural conditions, but abnormally high and abnormally low peaks are still easily visible (Figure 9.17). The more common extreme and diagnostic densities are shown above (Table 9.6).

Evaporite identification

Chemical deposits, because of their purity, may at least be suspected if not positively identified by their densities (Table 9.7). Care must be taken, as evaporites may be impure and densities will be altered. However, most evaporites tend to give intervals of constant density with very little variation. When this occurs, along with densities near the pure mineral values, evaporites are probable (Figure 9.18).