Chapter 16

Well Logging: Principles, Applications and Uncertainties

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16.1 Introduction

Well logging is a means of recording the physical, acoustic and electrical properties of the rocks penetrated by a well. It is carried out by service companies, which work under contract for the oil companies. Logging has the advantage that it measures *in situ* rock properties which cannot be measured in a laboratory from either core samples or cuttings.

Logging started with simple electric logs measuring the electrical conductivity of rocks, but it is now an advanced and sophisticated method used routinely in different phases of hydrocarbon exploration, field development and monitoring. It gives us a continuous downhole record that provides a detailed subsurface picture of both gradual and abrupt changes in physical properties from one bed to the next. By contrast, only selected parts of the reservoir rocks are cored, and samples of cuttings from the rest of the well give no more than a general idea of the lithology.

None of the logs actually measure the parameters that are of most interest to us, such as how much oil or gas is in the subsurface, or how much is being produced. Such important knowledge can only be derived, from the measured properties such as gamma radiation, density, velocity and resistivity, using a number of assumptions which, if true, will give reasonable estimates of hydrocarbons. To perform a logging operation on wireline, the measuring instrument is lowered into the borehole on the end of an insulated electrical cable after the drilling tool is pulled up (Fig. 16.1). The cable itself is used as the depth measuring device, so that properties measured by the tools can be related to particular depths in the borehole.

Well logs are usually recorded while the logging device is being winched upward through the well. The measurements from the instruments housed in the logging tool are recorded digitally at intervals of between 3 and 15 cm and the data is processed near the well on land, or on the platform in the case of offshore. Recording the well log involves a number of steps, beginning with sensing and pre-processing the measurement in the logging tool itself, transmission of this information to the surface over several kilometers of wireline, further processing in the logging truck computer, data storage on disc or magnetic tape, and finally display of the data on film or paper. A measured log shows many variations from top to bottom (log display in Fig. 16.1), and each wiggle has significance. Most logs are dependent on direct contact with the rock via the walls of the well, and have to be run after successive intervals of the drilling, before each stage of the steel casing is installed in the well.

16.2 Well Logs: The Necessity

Geological sampling during drilling (cuttings) provides a very imprecise record of the formations encountered. Entire formation samples can be brought to the surface by mechanical coring, but this is both slow and very expensive. In the narrowest sense, well logging supplements the analysis of cores, side-wall samples and cuttings. Logs are used for a variety of

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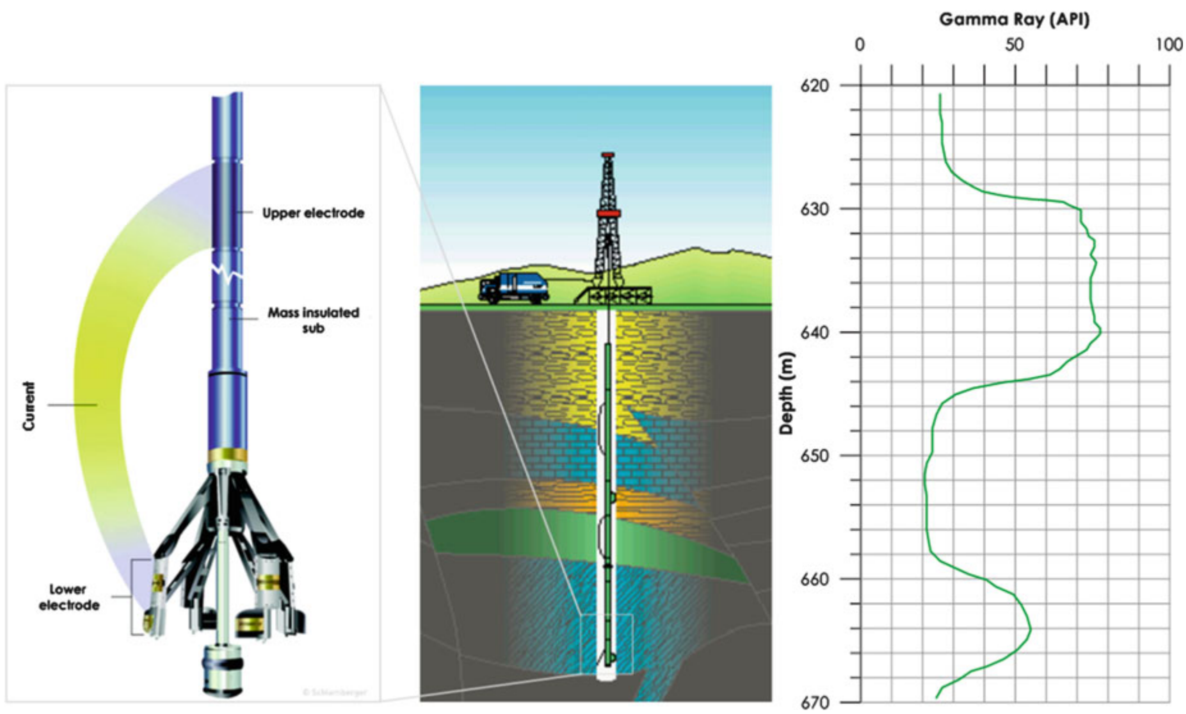

Fig. 16.1 Example of a logging tool (*left*, Courtesy of Schlumberger). The wireline logging operation showing logging truck, logging cable strung into the rig, then lowered into the borehole with logging tools at the end of the cable (*middle*). Example of a recorded gamma ray log display (*right*)

purposes depending on the nature of the data recorded. Correlation from well to well is one of the oldest and probably the most common use of logs. Correlation is usually based on the shapes of the recorded curves versus depth. It allows the subsurface geologist to map formation depths, lateral distributions and thicknesses, and then to identify conditions that could trap hydrocarbons. Identification of the lithology of the rock sequence is another important use. After acquiring experience in an area it is possible for a log analyst to make an educated guess as to lithology by looking at the log from a new well. A set of logs run in a well will usually mean different things to different professionals (Table 16.1). Currently, over fifty different types of these logging tools exist in order to meet various information needs and functions. Some of them are passive measurement devices, others exert some influence on the formation being traversed.

Pickett (1963) indicated some of the applications for well logs in petroleum engineering (Table 16.2). The applications fall into three categories: identification, estimation and production. Identification

Table 16.1 How is logging viewed by others? (Adapted from Ellis and Singer 2008)

The Geologist:
What depths are the formation tops?
Is the environment suitable for accumulation of hydrocarbon?
Is there evidence of hydrocarbons in this well?
What type of hydrocarbon?
Are hydrocarbons present in commercial quantities?
The Geophysicist:
Are the tops where you predicted?
Are the potential zones porous as you assumed from seismic data?
What does a synthetic seismic section show?
The Drilling Engineer:
What is the hole volume for cementing?
Where can you get a good packer seat for testing?
Where is the best place to set a Whipstock?
The Reservoir Engineer:
How thick is the pay zone?
How homogeneous is the formation?
What is the volume of hydrocarbon per cubic metre?
Will the well pay-out?
The Production Engineer:
Where should the production well be placed?
What kind of production rate can be expected?
Will there be any water production?
Is the potential pay zone hydraulically isolated?

Table 16.2 Uses of well logging in petroleum engineering (adapted from Pickett 1963)

Logging applications for petroleum engineering
Identification:
Rock type
Identification of geological environments
Location of fluid contacts (e.g. gas/oil, gas/water and oil/water contacts)
Fracture detection
Estimation:
Estimate of hydrocarbon in place
Estimate of recoverable hydrocarbon
Reservoir pressure
Porosity/pore-size distribution
Production:
Water flood feasibility
Reservoir quality mapping
Interzone fluid communication probability
Reservoir fluid movement monitoring

concerns subsurface mapping or correlation. Estimation is the more quantitative aspect of well logging, in which physical parameters such as water saturation or pressure are needed with some precision. The final category consists of well logging measurements which are used to monitor changes in a reservoir during its production phase.

16.3 Drilling Muds and Borehole Environments

During drilling a water-based, or sometimes oil-based, slurry containing clays and other natural materials, called drilling mud (drilling fluid), is pumped down the drill-string. Drilling muds are added to the wellbore to facilitate the drilling process by suspending cuttings, controlling pressure, stabilising exposed rock, providing buoyancy, and cooling and lubricating the drilling bit. Nowadays, drilling deeper, longer and more challenging wells is made possible due to more efficient and effective drilling fluids. High density materials (e.g. barite, hematite) are added to the drilling mud to increase its density and thereby its pressure on the walls of the well. The drilling fluid pumped down the borehole must ensure that the hydrostatic pressure in the wellbore exceeds the fluid pressure in the formation pore space to prevent disasters such as blowouts. The drilling mud helps to transport the rock fragments (cuttings) from the drill bit up to the surface (Fig. 16.2), where the cuttings are analysed for indications of hydrocarbon. Another important function of drilling fluids is rock stabilisation. Special additives ensure that the drilling fluid is not absorbed by the rock formation in the well and that the pores of the rock formation are not clogged.

Because the pressure in the drilling mud must exceed the formation pore pressure, the mud begins to enter permeable zones in the formation but is normally rapidly stopped by the build-up of a *mudcake* which lines the borehole wall (Fig. 16.2). The solid particles are concentrated there while the fluid penetrates the formation, first creating a flushed zone where nearly all the primary pore fluids are replaced by the fluids from the drilling mud. This part of the drilling mud is called the *mud filtrate*. Beyond this, there will be a zone where the primary pore fluids are partially replaced by drilling fluids, called the *transition zone*. The virgin formation fluids occupy the *uninvaded/undisturbed zone* further into the formation (Fig. 16.2). The depth of invasion is related to the permeability of the rock. Drilling mud extends furthest into porous sandstones but flushing and invasion will be rather limited in low permeability formations such as shales and tight sandstones. As the well is drilled deeper, further invasion occurs slowly through the mudcake, either dynamically, while mud is being circulated, or statically when the mud is stationary. In addition, the movement of the drill-string can dislodge some of the mudcake, allowing renewed invasion.

The replacement of oil by the water-based mud filtrate is by pressure-driven displacement. In water-bearing formations the mud filtrate replaces all of the formation water close to the borehole (Fig. 16.3a) but this decreases with depth of invasion. In oil-bearing formations the mud filtrate replaces all the formation water and most of the oil close to the borehole wall, again decreasing with distance into the formation (Fig 16.3b). Oil-based mud filtrates replace the fluids in the invaded zone by pressure-driven displacement

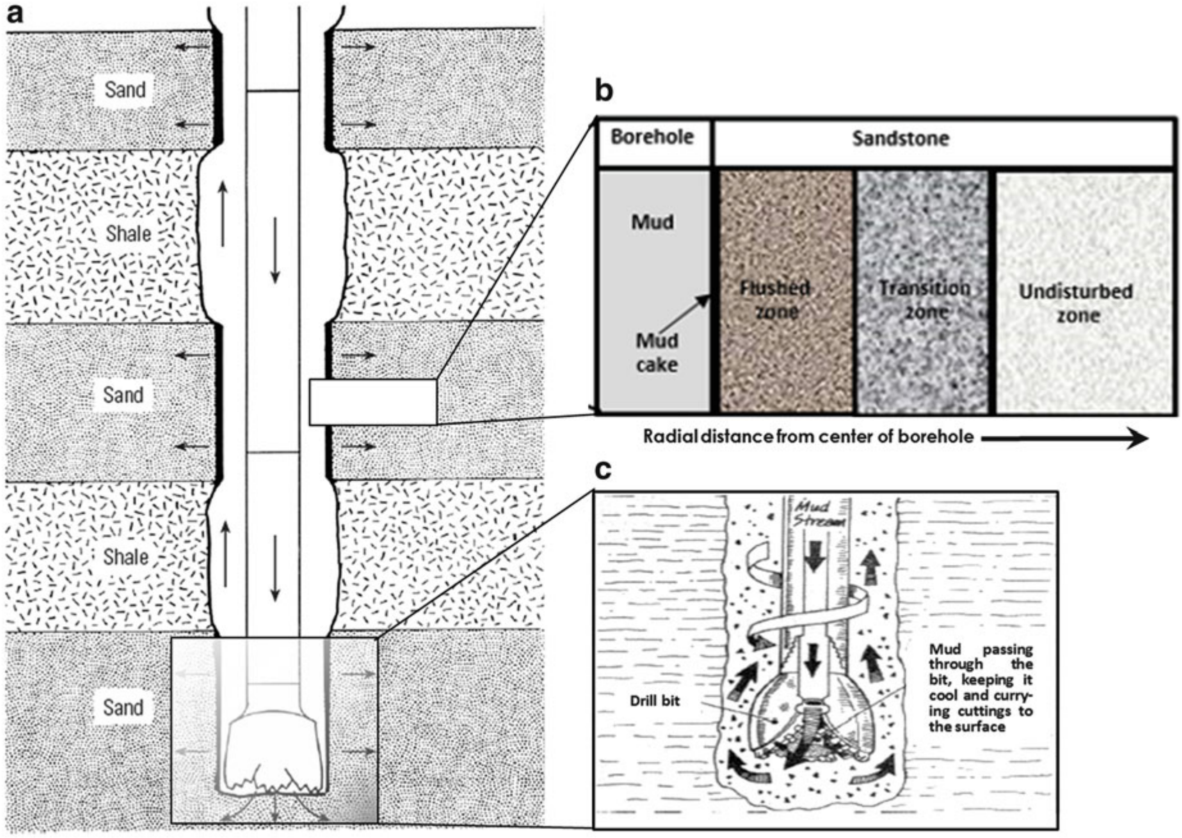

Fig. 16.2 The schematic diagram illustrates an idealised version of what happens when fluids from the borehole invade the porous and permeable sandstones and low permeability shales. The mud circulation causes borehole washout in the low permeability shale zones (**a**). Overpressured mud indicates that it is invading porous and permeable sandstones with the formation of a mudcake (**a** and **b**). During drilling, mud is pumped down the drill-string, forcing the cuttings up to the surface with the return flow (**c**)

alone. In water-bearing formations the oil-based mud filtrate does not replace all the formation water even close to the borehole wall (Fig. 16.3c), while in oil-bearing formations the oil-based mud filtrate only replaces the oil in the formation, leaving the formation water in place (Fig. 16.3d).

It is very important to know the type of drilling mud used, as this will determine the way in which it influences what is recorded on the logs. Salinity variations in mud may alter rock properties. Oil-based mud causes its own complications for log interpretation. To get good readings of the true subsurface properties of the rock, the tool has to either (1) measure accurately through the borehole mud, mud cake, flushed zone and transition zone, or (2) make readings closer to the tool (i.e. in the flushed zone) that can be reliably corrected to represent the values in the uninvaded zone. Wireline companies provide correction graphs for their various tools. However, the accuracy of the correction diminishes as the diameter of the borehole, the thickness of mud cake and the depth of invasion, increase.

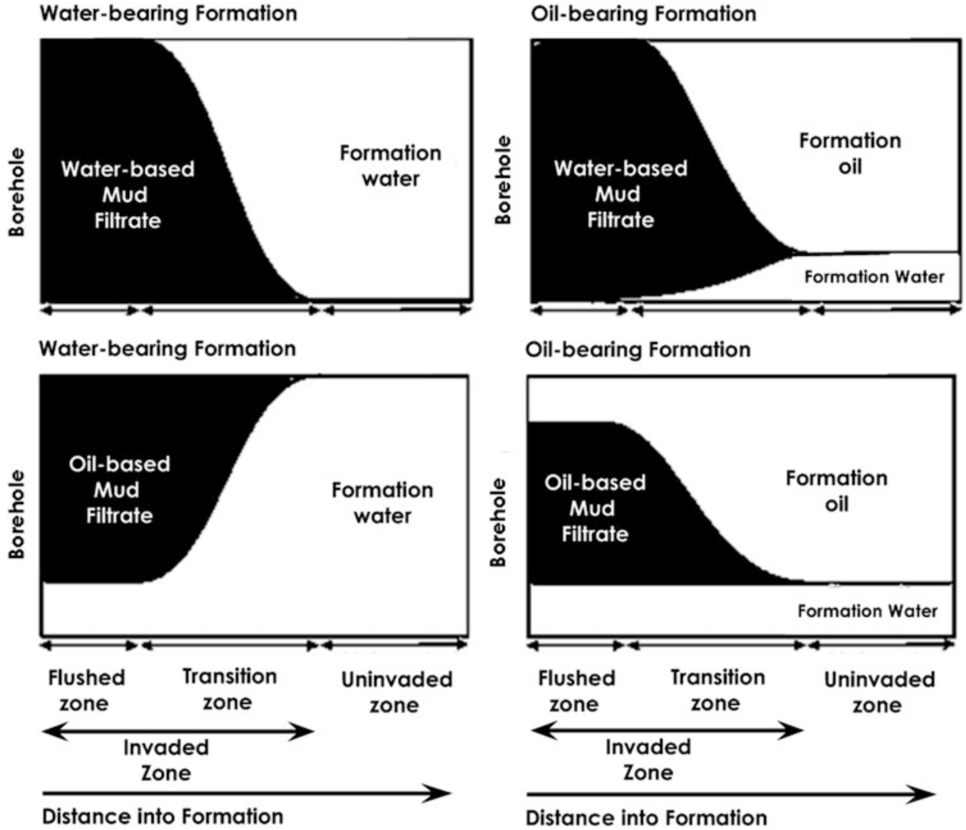

Fig. 16.3 Schematic indication of the distribution of pore fluids in the flushed, transition and uninvaded zones for water-based muds (*top*), and oil-based muds (*bottom*), in water- and oil-bearing formations

16.4 Measuring Techniques

Well logs measure in open hole, cased hole and parallel with drilling (Fig. 16.4). The conventional wireline logs that are run in a hole which has just been drilled, and before it is cased, are called *open-hole logs*. Open-hole logs require that the drill-string must be removed from the well before the logging tools can be lowered into the hole. Open hole logs are used to determine most petrophysical properties of the rocks. Logs run after the well is cased are called *cased-hole logs*. Most cased-hole logs are used to assess the integrity of the well completion and fluid flow into the well though some cased-hole logs can also be used to determine petrophysical properties. Most logs can now be recorded while drilling (i.e. do not need the drill-string be removed) and so measurements are available continuously as drilling proceeds. These logs are called *MWD* (Measurements While Drilling) and *LWD* (Logging While Drilling).

MWD and LWD are types of well logging where the measurement tools are incorporated into the drill-string and provide real-time information to help with steering the drill. These technologies were originally developed to partially or completely replace the open- and cased-hole logging. MWD and LWD offer the same measurements as wireline logging but in poor quality, lower resolution and less coverage. Information may be continuously transmitted to the surface by *mud pulses*, a common method of data transmission where a valve is operated to restrict the flow of the drilling mud according to the digital information to be transmitted. This creates pressure fluctuations representing the information. The pressure fluctuations propagate within the drilling fluid towards the surface where they are received from pressure sensors. At the surface, the received pressure signals are processed by computers to reconstruct the information. Alternatively, the data is recorded downhole and retrieved later when the instrument is brought back to the surface.

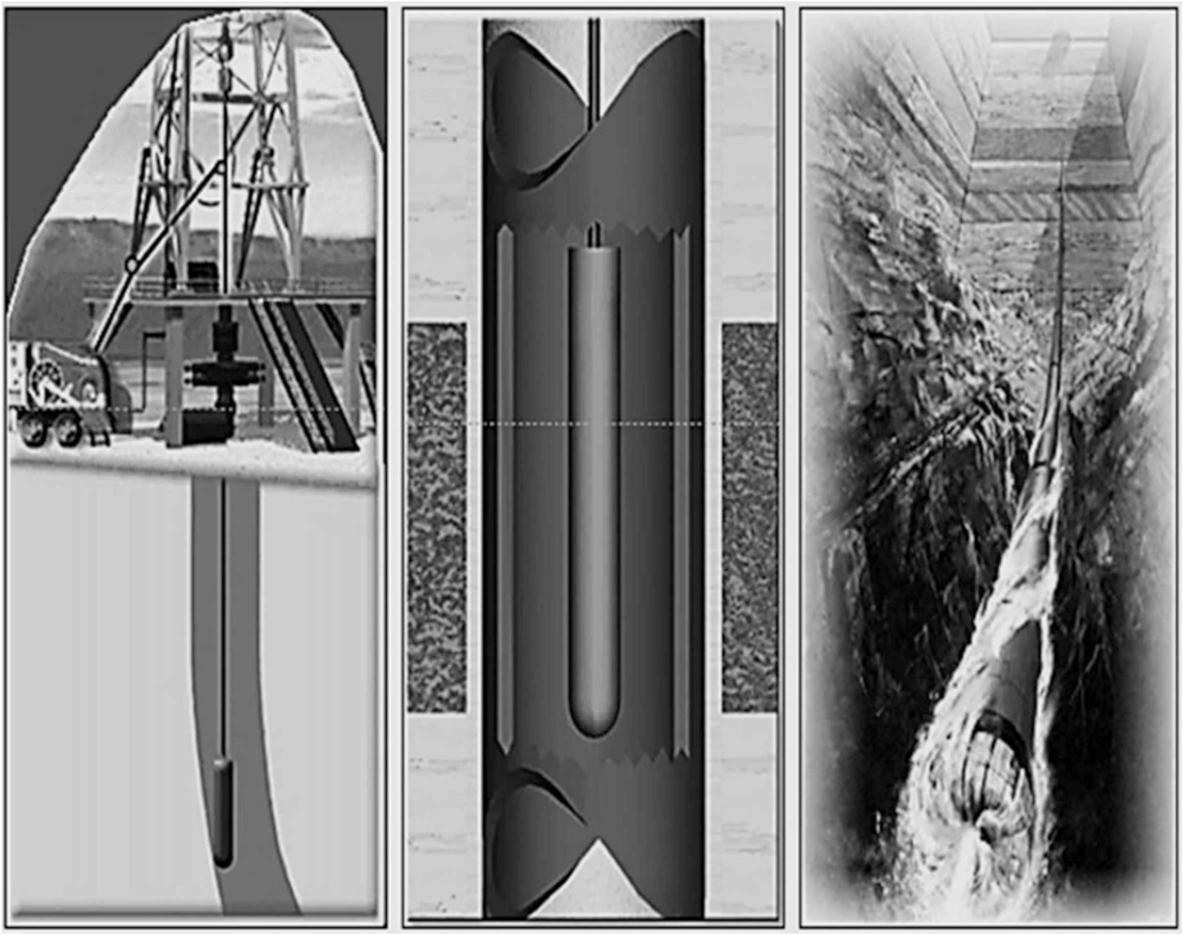

Fig. 16.4 Open hole (*left*), cased hole (*middle*) and LWD/MWD (*right*) logging techniques. Logs run in an open hole which has just been drilled but not cased. Logs run after the well is cased are called cased-hole logs. LWD and MWD are the general terms use to describe the logging techniques for gathering downhole data while drilling a well

Table 16.3 lists the main differences between LWD and conventional wireline logging. LWD tools are large instrumented drill collars, part of the bottom hole assembly. The sensors are arranged so that they can make relatively unimpeded measurements of the formation. MWD is a type of LWD where tools are encompassed in a single module in the steering tool of the drill-string at the end of the drilling apparatus (bottom hole assembly). Providing wellbore position, drillbit information and directional data, as well as real-time drilling information, MWD uses gyroscopes,

Table 16.3 Main differences between conventional wireline logging and LWD

Wireline	LWD
• Small, light and delicate	• Big, heavy and tough
• Since the 1930s	• Since the 1970s
• High data speed	• Slow telemetry
• Easy communication	• Limited control
• Good borehole contact	• Minimum borehole contact
• Powered through cable	• Batteries and mud turbine
• Takes more time	• Saves time
• Problem at high deviation	• Can log in any direction
• Susceptible to hole conditions	• More capable in tough conditions

magnetometers and accelerometers to determine borehole inclination and azimuth during the actual drilling.

Some information is logged on the rig, such as a mud log which may record up to five or ten properties of the drilling fluid, or a drilling log which records the rate of penetration and other functions of the drilling process. The stratigraphic log or sample description log, records the site geologists' identification of the rock samples retrieved from the drilling mud, together with qualitative or interpretive data concerning evidence of the fluid content of the rock, and thus is one of the primary sources of rock and fluid descriptions for the well.

16.5 Logging Tools

Logging tools have been developed over the years to measure radioactivity (e.g. *Gamma Ray*, *Neutron* and *Density* logs), electrical properties (e.g. *SP*, *Induction* and *Resistivity* logs), acoustic properties (*Sonic* log), nuclear magnetic resonance (*NMR* log), pressure, and many other properties of the rocks and their contained fluids. Other logs, which measure properties of the wellbore itself, are *Caliper*, *Temperature*, *Image* and *Dipmeter* logs. Despite the availability of this rather large number of devices, each providing complementary information, the final answers derived are mainly (1) the location of hydrocarbon-bearing formations, (2) an estimate of their producibility, and (3) an assessment of the quantity of hydrocarbon in place in the reservoir. Note that the greatest variety of logging tools is run in the area that is expected to be of greatest interest, i.e. the reservoir.

Most tools have a shallow depth of investigation, resulting in the measurement of the formation in the flushed or transition zones (Fig. 16.5). Most radiation tools (e.g. *Gamma Ray*, *Neutron* and *Density* logs) have an investigation depth of less than 0.5 m. Electrical tools (e.g. *Microlog*, *Laterolog*, *Induction* log) come in various versions with a wide range of investigation depths, from the micro-tool, which measures only the mud cake (a few centimetres), to the deep penetration tools (induction log, up to 5 m). The depth of investigation often depends upon the density/porosity of the formation. Because of the wide variety of subsurface geological formations, many different logging tools are needed to give the best possible combination of measurements for the rock type anticipated. The following are the principles, most common applications and uncertainties of the most important types of log:

16.5.1 Temperature Log

16.5.1.1 Generalities and Basic Principles

The temperature log is a tool for measuring the borehole temperature. Readings from a number of thermometers attached to different tool combinations and run at different times are analysed (Fig. 16.6) to give the temperature at the bottom of the borehole (bottom hole temperature, BHT). Temperature in the

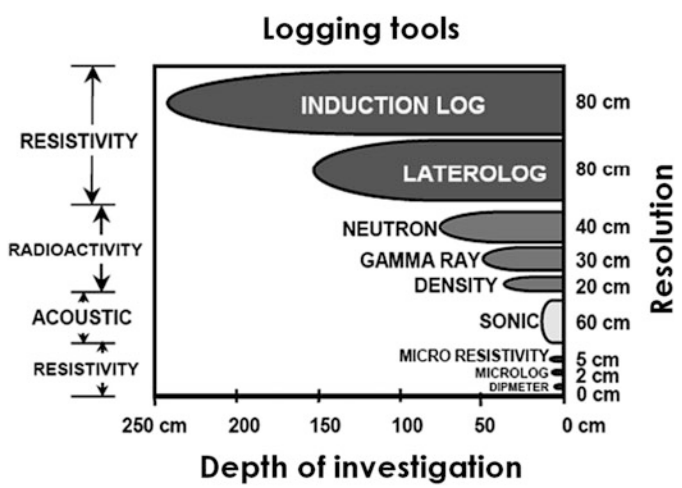

Fig. 16.5 Depth of investigation of common logging tools

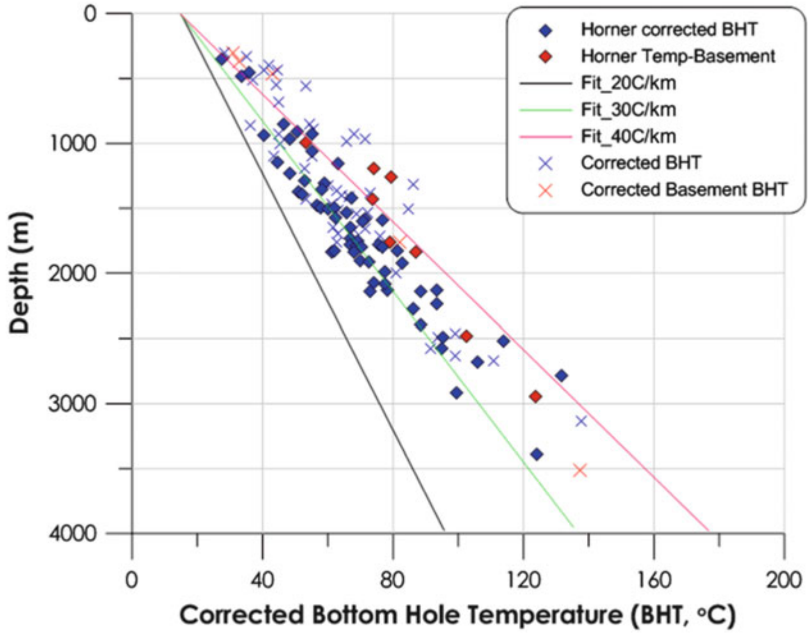

Fig. 16.6 Plot of measured and estimated bottom hole temperatures (BHT) and geothermal/temperature gradients with depth for wells is a sedimentary basin

subsurface increases with depth. The rate at which it does so is called the *geothermal gradient* (g_G), or simply *geotherm*. The first step involved in determining temperature at a particular depth is to determine the geotherm of the region.

Low thermal conductivity rocks, such as shale, act as a thermal insulator and have a large temperature gradient across them, while high thermal conductivity rocks, such as salt, permit the conduction of heat efficiently and have a small temperature gradient across them. Geothermal gradient is commonly expressed in degrees celsius per 100 m (°C/100 m). If the geothermal gradient of an area is not known, then it can be determined by the following formula:

$$g_G = (BHT - Tms/TD) \times 100 \tag{16.1}$$

where *BHT* is the bottom hole temperature, *TD* is the total depth and T_{ms} is the mean surface temperature. Typical geotherms for reservoirs are about 20–35°C/km, although significantly higher values (up to 85°C/km) can be found in tectonically active areas, and lower ones (0.05°C/km) in stable continental platforms. Once the geothermal gradient has been established, it is possible to determine the temperature for a particular depth (*D*) using the following formula. This is often referred to as *formation temperature* (T_f).

$$T_f = Tms + [g_G(D/100)] \tag{16.2}$$

16.5.1.2 Uses of Temperature Log

Temperature logs have many applications, with the most common being to identify zones producing or accumulating fluid, to evaluate a cement or hydraulic fracture treatment, and to locate lost circulation zones and casing leaks. Geothermal gradients in sedimentary basins are extremely important for the calculations necessary for predicting kerogen maturation, detection of fluid movement, subsurface pressures, and for the general modelling of basin subsidence. Since temperature takes time to dissipate, a temperature log tends to reflect the behaviour of a well over a longer time period than other measurements.

16.5.1.3 Uncertainties of Temperature Log

Temperature measurements made during drilling (MWD and LWD) consistently underestimate the formation temperature because drilling mud is being circulated. Temperature measurements made on wireline logs sometime after the drilling fluid circulation has stopped also underestimate the formation temperature, but less so than MWD and LWD as the formation is now in the process of reheating the borehole. Drilling mud takes several days or even weeks before its temperature approaches that of the formation water, and there is therefore considerable uncertainty involved in such temperature calculations.

16.5.2 Caliper Log

16.5.2.1 Generalities and Basic Principles

The caliper log measures borehole diameter and shape. Nowadays, caliper logs also record the three-dimensional shape of the borehole walls. It has two, four, or more extendable arms (Fig. 16.7) which can move in and out as the tool is drawn up the borehole. These movements are converted into electrical signals by a potentiometer. Normally caliper log readings represent the caliper value minus the drill bit diameter and thus record cavities where the well has caved in, and also indicate the competence of the rocks cut during drilling (Fig. 16.7). The scale is generally given in inches, which is standard for measuring bit sizes. Table 16.4 describes the main influences on caliper values. A hole with the same diameter as the bit-size is called *on gauge*.

16.5.2.2 Uses of Caliper Log

The common uses of the caliper log are as follows:

- Indication of borehole quality for the assessment of the quality of other logs whose data quality is degraded by boreholes that are out of gauge.
- Contributory information for lithological assessment, and as indicator of good permeability and porosity zones (reservoir rocks) due to development of mudcake.

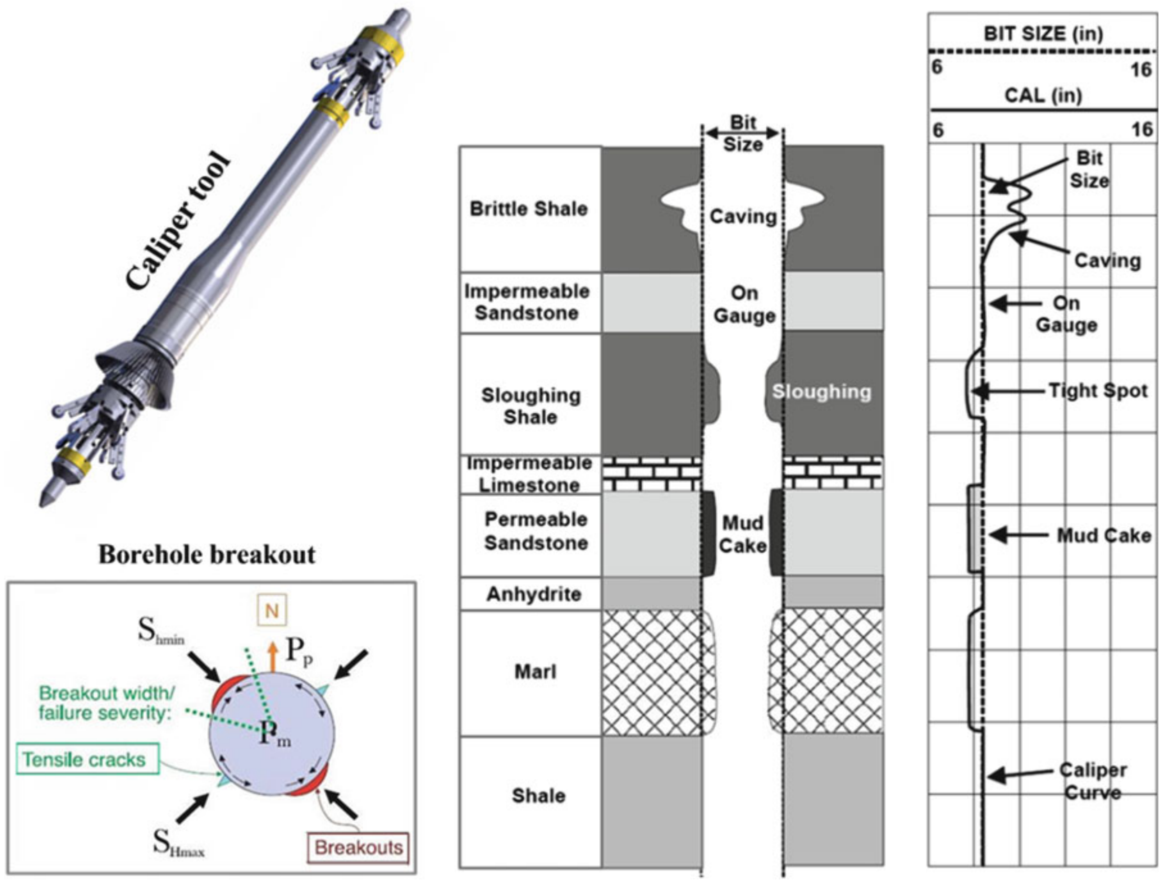

Fig. 16.7 Typical caliper log responses to various lithologies (*right*). Mutli-arm and multi-sensor caliper tool (*upper-left*). Ellipticity of borehole can help to identify direction of principal stresses (*lower-left*). (Modified from Rider 2004)

Table 16.4 Factors influencing caliper responses

Hole diameter	Cause	Possible lithologies
On gauge	Well-consolidated formations Non-permeable formations	Massive sandstones Calcareous shales Igneous rocks Metamorphic rocks
Larger than bit size	Formations soluble in drilling mud Weak formations and caving	Salt formation drilled with freshwater Unconsolidated sands, gravels, brittle shales
Smaller than bit size	Formations that swell and flow into borehole Development of mudcake with porous and permeable formations	Swelling shales Porous, permeable sandstones

- Estimation of mudcake thickness, $h_{mc} = (d_{bit} - d_h)/2$, where h stands for the hole, in inches.
- Measurement of borehole volume, $V_h = (d_h^2/2) + 1.2\%$, in litres per metre.
- Measurement of required cement volume, $V_{cement} = 0.5 \times (d_h^2 - d^2_{casing}) + 1\%$, in litres per metre.
- Selection of consolidated formations for wireline pressure tests, recovery of fluid samples, and for packer seating for well testing purposes.

16.5.2.3 Uncertainties of Caliper Log

Known challenges with caliper logging include borehole spiralling. The position of the drill bit may precess as it drills, leading to spiraling shapes in the wellbore wall, as if the hole had been drilled by a screw. If the arms of the caliper log follow the grooves of the spiral, it will report too high an average diameter. Moving in and out of the grooves, the caliper will give erratic or periodically varying readings. In most cases, the borehole's circumference will not be a perfect circle and therefore a caliper tool with several arms is required to obtain a true understanding of the size and shape of the borehole. The borehole can change to an oval shape after drilling, which can cause the caliper log to overestimate the size of the borehole.

16.5.3 Self-Potential/Spontaneous Potential (SP) Log

16.5.3.1 Generalities and Basic Principles

The self-potential/spontaneous potential log (SP) was the first wireline logging tool used in hydrocarbon exploration. It is very simple, requiring only an electrode in the borehole and a reference electrode at the surface (Fig. 16.8). A current is created by the difference in the concentrations of electrolytes in the liquid phases. There are three requirements for the existence of an SP current: (1) a conductive borehole fluid (i.e. a water-based mud), (2) a porous and permeable bed sandwiched between low porosity and impermeable formations, and (3) a difference in salinity between the borehole, in most cases the mud filtrate, and the formation fluid. This log has no absolute scale – it is the relative changes in the SP log that are important. SP is measured in mV (millivolts). A relative scale of 10 mV/small division is usually used. Value range is typically approximately ±50 mV about the 0 mV for shale baseline, while sandstones

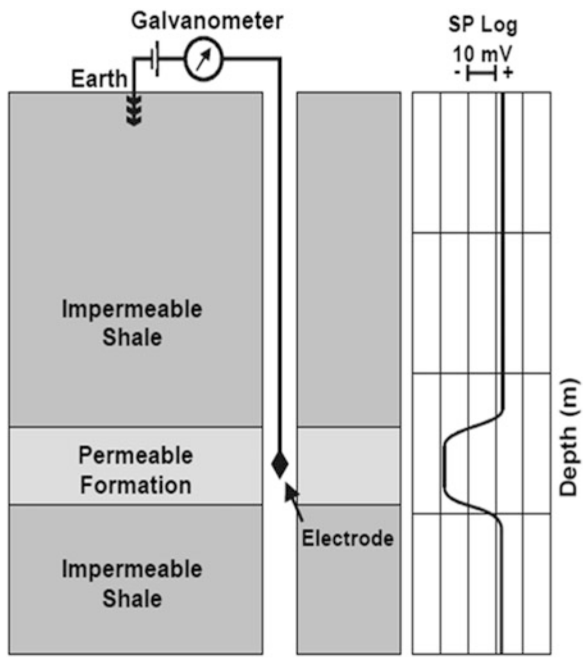

Fig. 16.8 The SP tool arrangement and typical log responses for permeable sandstone and impermeable shales

produce more negative (to the left) (Fig. 16.8) or positive values based on salinity variations between drilling mud and formation water.

SP measures the naturally occurring electrical potential (voltage) produced by the interaction of formation water, conductive drilling fluid and shale. There are three sources of the currents; two are *electrochemical potential* (*liquid junction potential* and *membrane potential*), and one *electrokinetic potential*. The liquid junction potential and the membrane potential are the main components of SP deflection. The Na^+ and Cl^- ions have different nobilities at the junction of the invaded and virgin zones. The ion movement across this boundary generates a current flow and hence a potential. The greater the difference between the salinity of the solutions (mud and formation water), the greater the potential. In low porosity, low permeability formations, the mudcake builds slowly and the electrokinetic potential becomes predominant. Electrokinetic potential is generated by the flow of mud filtrate through a porous permeable bed. It depends upon the resistivity of the mud filtrate and will only become important if there are high differential pressures across the formation. The effects are normally negligible in permeable formations because the mudcake builds quickly and halts any further invasion.

16.5.3.2 Uses of SP Log

The SP log has several applications: (1) indication of the shaliness of a formation, (2) correlation of stratigraphic sequences, (3) detection of permeable beds, (4) determination of formation water resistivity (R_w), and (5) detection of hydrocarbons by the suppression of the SP curve. The two most common applications are described below:

Shale Volume Estimation

The volume of shale is used in the evaluation of shaly sand reservoirs and as a mapping parameter for both sandstone and carbonate facies analysis. The following relationships are used to estimate shale volume (V_{sh}) from the SP log (Fig. 16.9):

$$V_{sh} = (1 - PSP/SSP) \quad (16.3)$$

$$V_{sh} = [(PSP - SSP)/(SP_{shale} - SSP)] \quad (16.4)$$

where PSP (pseudostatic spontaneous potential) is the log reading in a thick homogeneous shaly sand zone,

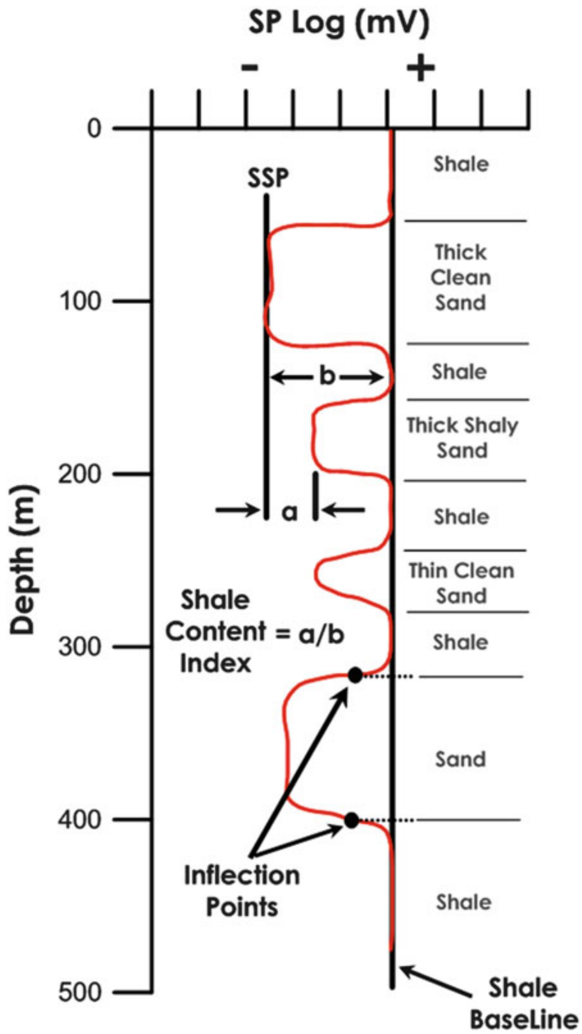

Fig. 16.9 Example of the shale baseline and the SSP defined on an SP log. The shale base line is the maximum positive deflection (in this example) and occurs against shale. The SSP is a maximum negative deflection and occurs against clean, porous and permeable water-bearing sandstone

SSP (static spontaneous potential) is the SP log reading in a thick clean sand zone and SP_{shale} is the *shale baseline*. This assumes a linear mixing relationship between the SP log and shale volume and has no theoretical basis; it probably overestimates the shale volume.

Identification of Facies and Depositional Environments

The SP log can be used to follow facies changes. SP deflections often respond to changes in depositional

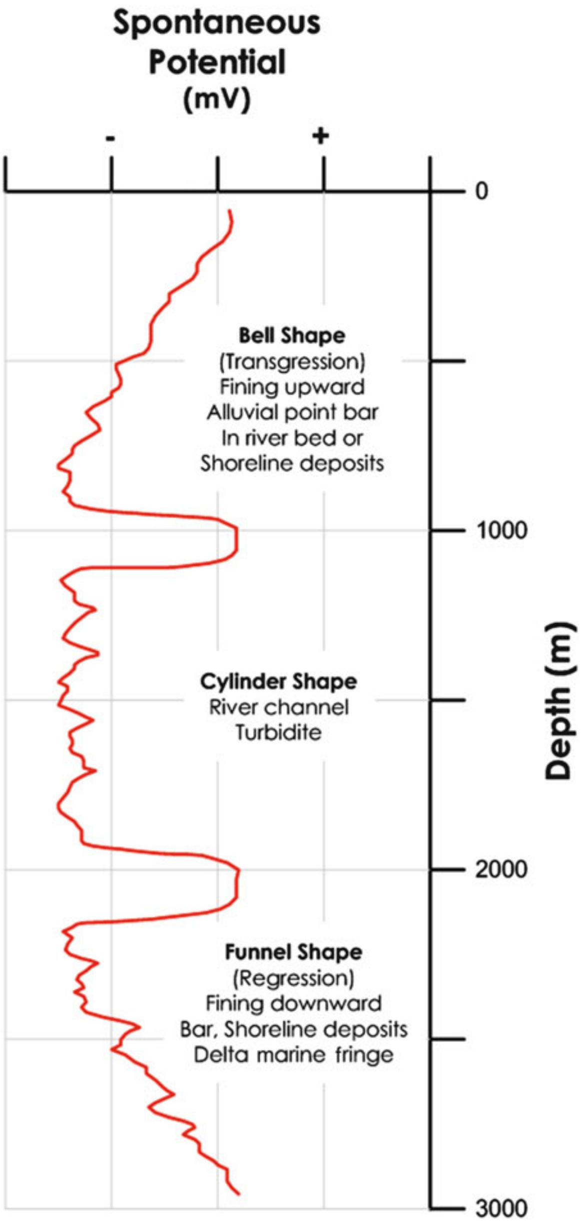

Fig. 16.10 Facies identification using the SP log. A typical fining-upwards, channel sandstone giving a bell-shaped SP curve

environment. Characteristic SP shapes are produced in channels, bars, and other depositional sequences where sorting, grain size or cementation changes with depth (Fig. 16.10). These shapes are called bells, cylinders or funnels. A typical fining-upwards, channel sandstone gives a bell-shaped SP curve. The SP log is sometimes useful for stratigraphic correlation, but is rarely used alone. Nowadays it has been mostly replaced by the GR log, which has a higher resolution and is more reliable.

16.5.3.3 Uncertainties of SP Log

The SP log has several limitations such as (1) borehole mud must be conductive: when using an oil-based mud readings cannot be obtained from SP logs, (2) a sequence of permeable and impermeable zones must exist, (3) little or no deflection occurs if resistivity of mud/mud filtrate is close/equal to resistivity of formation water, and (4) SP response will not fully develop in front of thin beds. The log has a low vertical resolution and is rarely useful in offshore environments. Although it can be used for correlation, it is best not to rely solely upon it.

16.5.4 Gamma Ray and Spectral Gamma Ray Logs

16.5.4.1 Generalities and Basic Principles

The *gamma ray (GR)* log measures the total natural gamma radiation whereas the *spectral gamma (SGR) ray* log measures the natural gamma radiation emanating from a formation split into contributions from each of the major radio-isotopic sources (Fig. 16.11). Gamma ray log is combinable with all other logging tools, and is almost always used as part of every logging combination run because of its ability to match the depths of data from each run. An advantage of the gamma ray log over some other types of well logs is that it works through the steel and cement walls of cased boreholes and is insensitive to drilling fluids. The unit of gamma ray log is API (American Petroleum Institute).

The gamma radiation originates from potassium (K^{40}) and the isotopes of uranium-radium and thorium series. Potassium is by far the most abundant of the three elements but its contribution to the overall radioactivity in relation to its weight is small. Each of the three sources emits gamma rays spontaneously. They emit photons with no mass and no charge but great energy. One of the characteristics of gamma rays is that when they pass through any material their energy is progressively absorbed. The effect is known as *Compton scattering*, and is due to the collision between gamma rays and electrons that produces a degradation of energy.

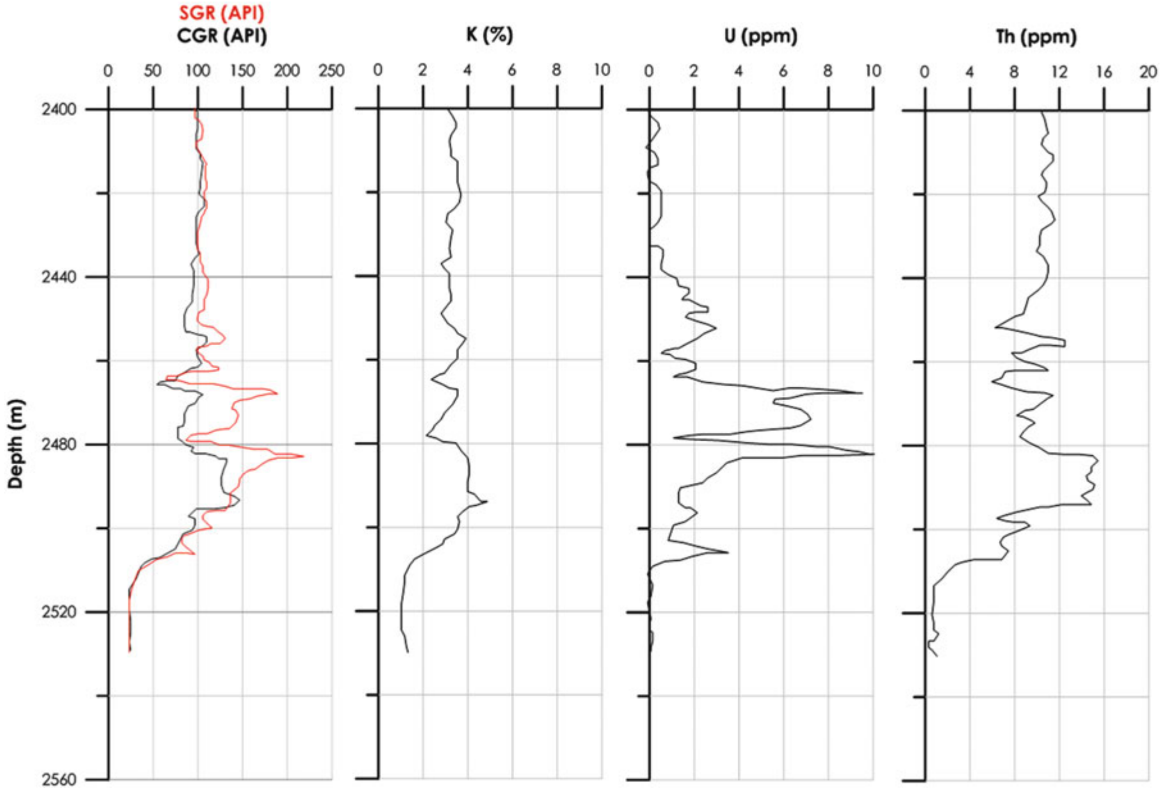

Fig. 16.11 Some typical responses of gamma ray and spectral gamma ray logs against different lithologies. The spectral gamma ray responses show individual contributions of thorium, potassium and uranium to the overall radioactivity

16.5.4.2 Uses of Gamma and Spectral Gamma Ray Logs

The gamma ray is a simple but very useful log. High vertical resolution makes it particularly well suited for depth matching and fine-scale correlation. The other most common uses of gamma and spectral gamma ray logs are (1) lithology discrimination, (2) shale volume estimation, and (3) analysis of facies and depositional environment.

Lithology Discrimination

A prime application of the gamma ray log is for discrimination of different lithologies (Fig. 16.12). While it cannot uniquely define any lithology, the information it provides is invaluable when combined with information from other logs. Shales, organic-rich shales and volcanic ash show the highest gamma ray values, while halite, anhydrite, coal, clean sandstones, limestone and dolomite have the lowest values. This difference in radioactivity between shales and sandstones/carbonates allows the gamma tool to distinguish between shales and non-shales. Care must be taken not to overgeneralise these rules. For example a clean sandstone may contain feldspars (arkosic sandstones), micas (micaceous sandstones) or both (greywackes), or glauconite, or heavy minerals, any of which will give the sandstone higher gamma ray values than would be expected from a pure quartzitic sandstone.

Black shales (e.g. hydrocarbon source rocks) in particular, with their substantial organic content, produce marked responses on the gamma ray log because they normally have a higher uranium content than other shales. The Kimmeridge (Upper Jurassic) shale in the North Sea contains 2–10 ppm uranium and is often referred to as the "hot shale". Normally shales contain <1 ppm uranium, but 10–12 ppm thorium, which represents ~50% of the total radioactivity. Limestones have very low concentrations of U, Th and K, and give very low gamma-ray responses. In evaporite sequences, however, gamma logs are very sensitive indicators of potassium salts.

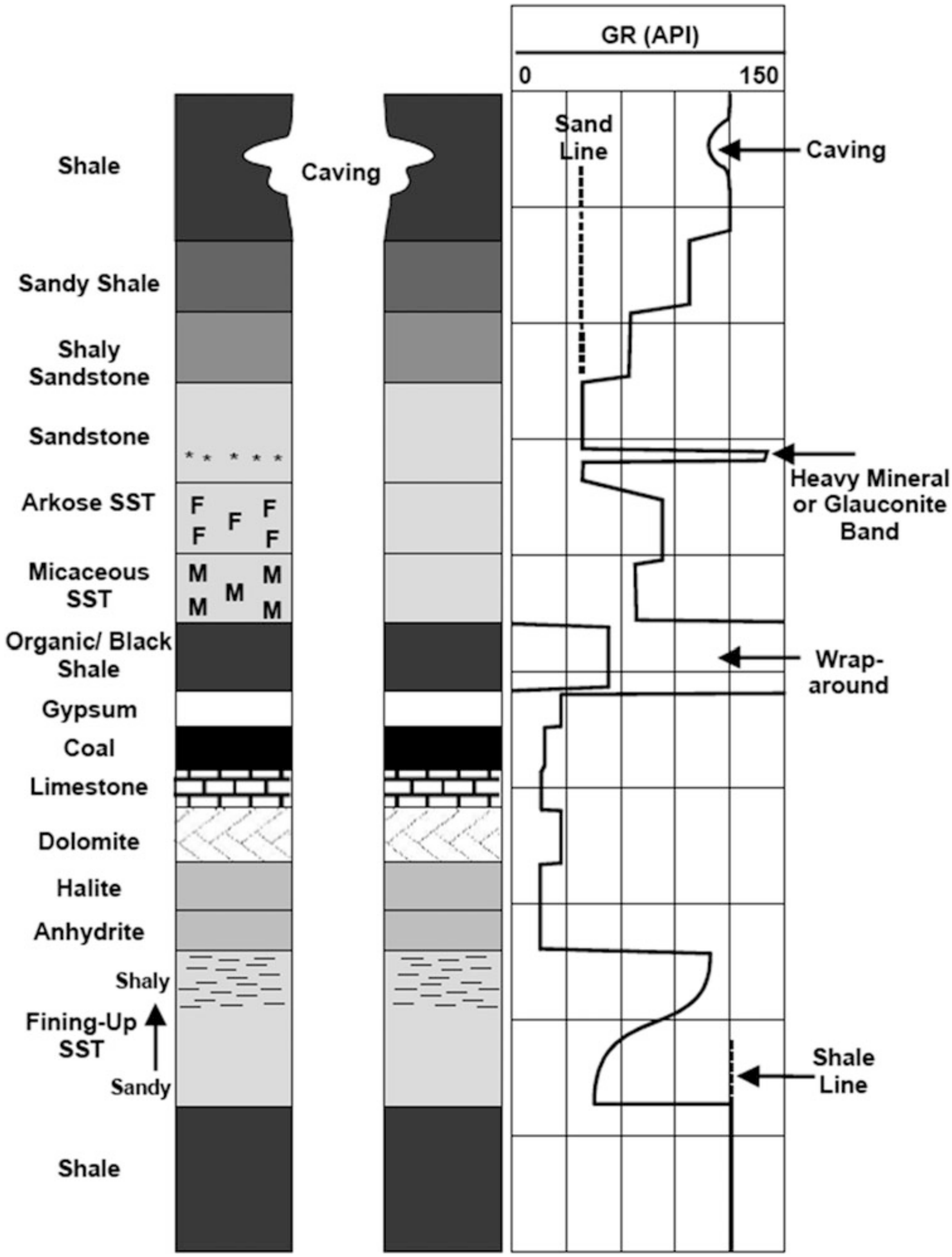

Fig. 16.12 Gamma ray log responses for common lithologies. (Modified from Rider 2004)

Shale Volume Estimation (V_{sh})

In most reservoirs the lithologies are quite simple, being cycles of sandstones and shales or carbonates and shales. Once the main lithologies have been identified, the gamma ray log values can be used to calculate the shaliness or shale volume (V_{sh}) of the rock. This is important, as a threshold value of shale volume is often used to help discriminate between reservoir and non-reservoir rocks. Shale volume is calculated in the following way: First the gamma ray index (I_{GR}) is calculated from the gamma ray log data using the following relationship

$$I_{GR} = \left[\left(GR_{log} - GR_{min}\right)/\left(GR_{max} - GR_{min}\right)\right] \quad (16.5)$$

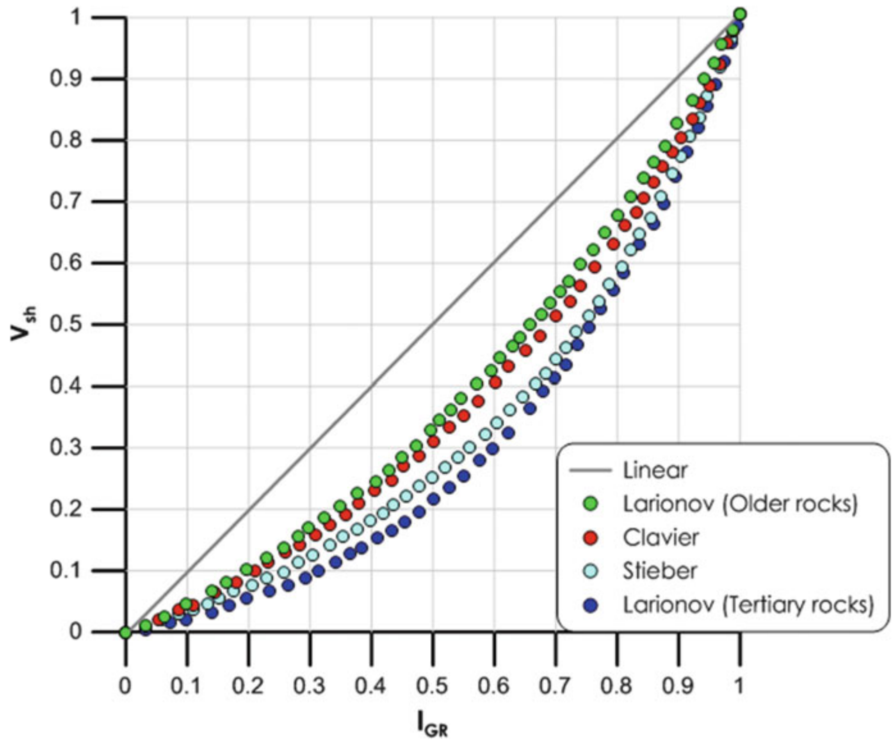

Fig. 16.13 The chart for corrected V_{sh} estimation

where GR_{log} is the gamma ray reading at the depth of interest, GR_{min} is the minimum gamma ray reading (usually the mean minimum through a clean sandstone or carbonate formation), GR_{max} is the maximum gamma ray reading (usually the mean maximum through a shale or clay formation). Many petrophysicists assume that $V_{sh} = I_{GR}$ though there is no scientific basis for assuming a linear relation of V_{sh} and I_{GR}. However, to be correct the value of I_{GR} should be entered into the chart shown as Fig. 16.13, from which the corresponding value of V_{sh} may be read.

It should be noted that the calculation of shale volume is a 'black art' as much depends upon the experience of the geoscientist in defining the GR_{min} (*sand line*) and the GR_{max} (*shale line*) values (Fig. 16.13), noting that the sand line and/or shale line may be at one gamma ray value in one part of the well and at another gamma ray value at another level. Once the shale volume has been calculated, a threshold shale volume may be defined which will divide the well into a number of reservoir and non-reservoir zones.

Facies and Depositional Environment Analysis
Gamma ray logs help to identify thin beds and so are widely used for lithological correlation and depth matching between different logging runs. As mentioned earlier, the gamma ray log is often used to measure the shaliness of a formation. In reality the shaliness often does not change suddenly, but gradually with depth. Such gradual changes are indicative of the litho-facies and the depositional environment of the rock, and are associated with changes in grain size and sorting that are controlled by facies and depositional environments. Figure 16.14 analyses the shape of gamma ray log responses for various depositional environments. All possible combinations of these shapes may be encountered.

The *cylinder shapes* represent uniform deposition and are interpreted as aeolian dune, tidal sand, fluvial and turbidite channel and proximal deepsea fan deposits. The *bell shapes* represent the fining-upward sequences and are interpreted as tidal sand, alluvial sand, fluvial channel, point bar, lacustrine, delta, turbidity channel and proximal deepsea fan deposits. The *funnel shapes* represent coarsening-upward sequences

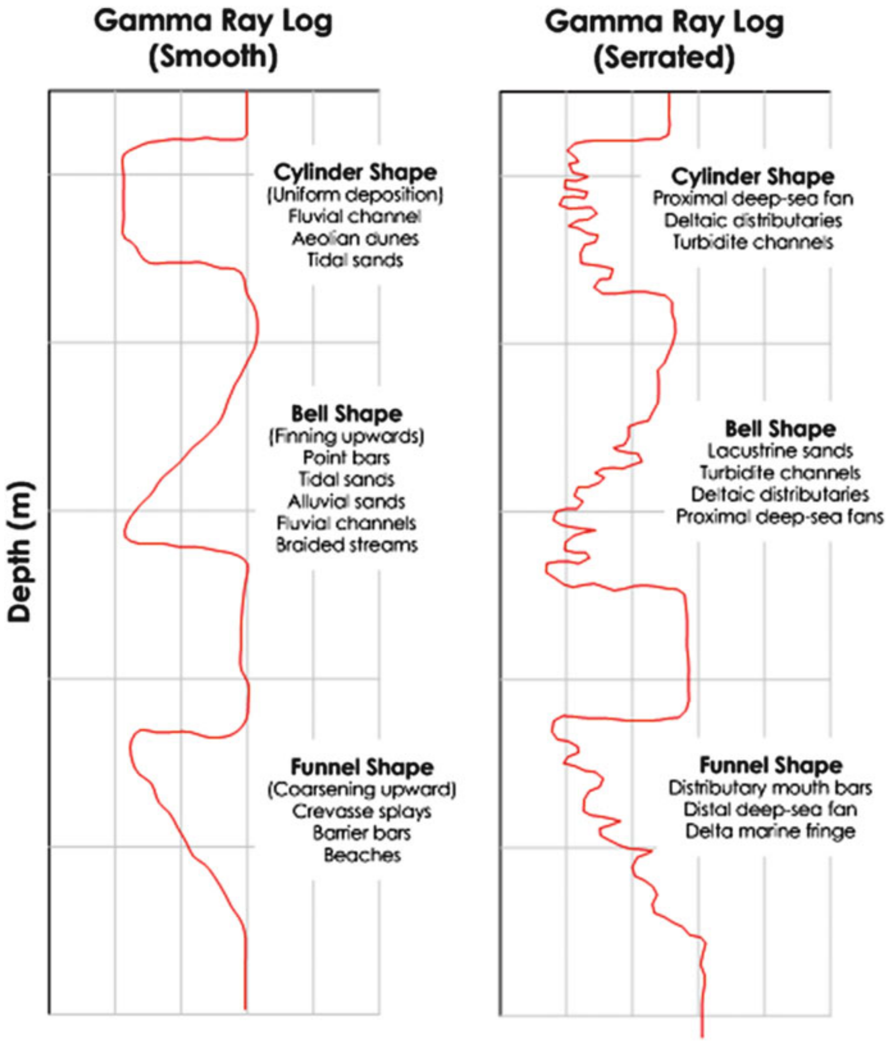

Fig. 16.14 The gamma ray log responses and their application to interpret depositional facies and depositional environments

that are interpretated as barrier bar, beach sand and crevasse splay, distributary mouth bar and distal deepsea fan deposits.

16.5.4.3 Uncertainties of Gamma and Spectral Gamma Ray Logs

The gamma ray log usually runs centered in the borehole. If the borehole suffers from caving, the gamma ray log can be badly affected and underestimated (Fig. 16.15). The measured underestimation should be corrected from the caliper log. The mud density affects the gamma ray as higher density muds (e.g. barite) attenuate the gamma ray and will give an anomalously low gamma ray reading. KCl-based muds have a natural gamma radioactivity associated with potassium. The radiation from KCl-based muds contributes to the gamma ray and increases significantly the total gamma ray count (Fig. 16.15).

For standard GR logs the value measured is calculated from thorium in ppm, uranium in ppm and potassium in percent. Due to the mass of uranium concentration in the calculation, anomalous concentrations of uranium can cause clean sand reservoirs to appear shaly. The spectral gamma ray log is used to provide an individual reading for each element, enabling concentration anomalies to be identified and interpreted. Sometimes non-shales also have elevated levels of gamma radiation. Sandstone can contain uranium, potassium feldspar, clay filling or rock fragments that cause it to have higher-than-usual

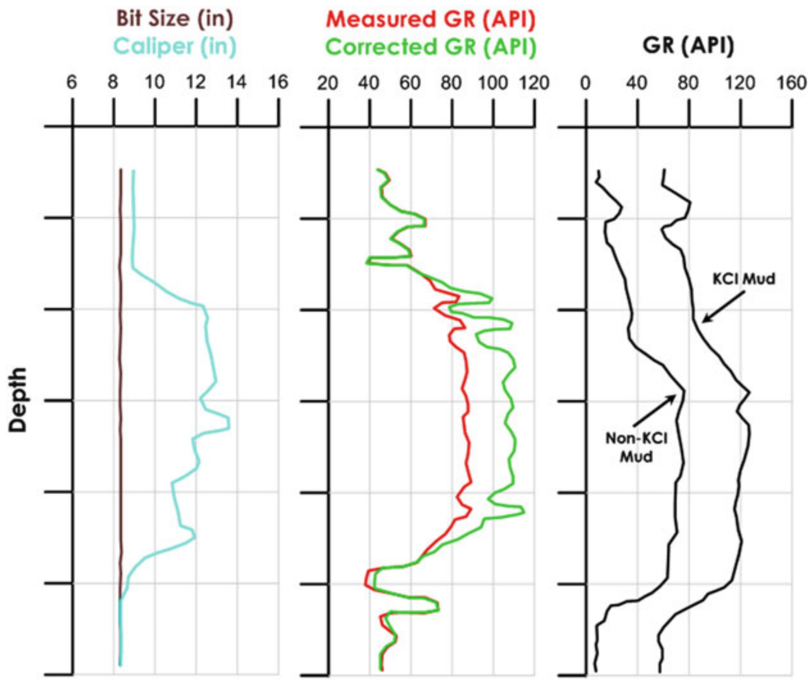

Fig. 16.15 Effect of caving and KCl drilling mud on the gamma ray log readings

gamma readings. Coal and dolomite may contain absorbed uranium. Evaporite deposits may include potassium minerals such as carnallite. When this is the case, spectral gamma ray logging can be done to identify these anomalies.

16.5.5 Porosity Logs

16.5.5.1 Generalities and Basic Principles

Evaluating porosity is an important petrophysical task in formation evaluation. The porosity of a formation can be estimated either from neutron, density, sonic or NMR logging. None of these logs measure porosity directly. The density, neutron and NMR logs are nuclear measurements whereas the sonic log uses acoustic measurements. When using a single porosity log, the true porosity is calculated from interpolation between the values for the matrix mineral and the pore fluid. A combination of porosity logs gives more accurate estimates of porosity and valuable indications for lithology. The basic principles of four porosity logs are given below:

Neutron Log

A neutron log is obtained using a neutron source, which sends radiation into the rocks (Fig. 16.16). The neutron rays are absorbed by rock, and particularly by the water in the formation. This is due to collisions with atomic nuclei, and the absorption of the neutron radiation is primarily a function of hydrogen atom concentrations (hydrogen index). Since most of the hydrogen in rocks is present as water, neutron logs provide an expression of the water content and thereby the porosity of a rock. The common density tools are GNT (gamma-ray neutron tool), SNT (sidewall neutron tool), CNL (compensated neutron log) and DNL (dual neutron log). Neutron logs are displayed as neutron porosity and common units are p.u. (porosity unit), decimal or %.

In shales and sandstones with high clay content the neutron logs record higher porosity because hydrogen is also present in the clay minerals which are part of the solid phase. This is called the *shale effect* and is most pronounced in shales with high content of smectite and kaolinite compared to those with mostly illite and chlorite. Limestones however give very reliable porosity values because carbonate minerals contain little hydrogen. Calculation of porosity based on neutron logs (neutron porosity) results in too low porosity values when the pores are filled with gas because they contain less hydrogen per volume compared to water and oil. This is called the *gas effect*. Gas is less dense and has fewer hydrogen atoms per unit volume than water and oil, and therefore has a lower hydrogen

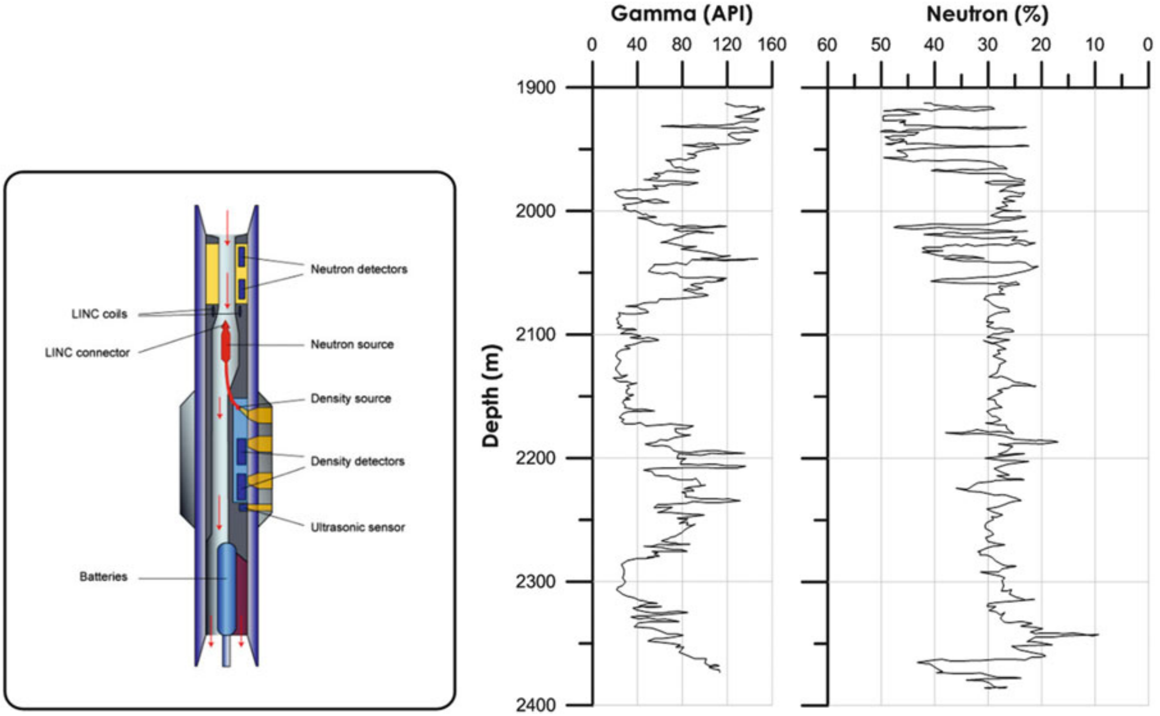

Fig. 16.16 The neutron tool and log response against mixtures of shales and sandstones. The gamma ray log responses for the sequence are also presented

index. Neutron logs can therefore be used to detect gas and distinguish it from oil.

Density Log

The density tools are induced radiation tools. They bombard the formation with gamma radiation and measure how much radiation returns to the sensors. The tool consists of a radioactive source (usually caesium-137 or cobalt-60) that emits gamma rays of medium energy (in the range 0.2–2 MeV). The tool has short- and long-spaced detectors (Fig. 16.17). The common density tools are FDC (formation density compensated), LDT (litho-density tool), CDS (compensated density) and PDS (photoelectric density). Returning gamma rays are measured at two different energy levels: (1) higher energy gamma rays (Compton scattering) determine bulk density and therefore porosity (e.g. FDC, CDS tools) and (2) low energy gamma rays (due to photoelectric effect) are used to determine formation lithology (e.g. LDT and PDS). The low energy gamma rays show little dependence on porosity and fluid and so are very useful for lithology identification. The density log unit is g/cm^3 or kg/m^3. The unit of the photoelectric log is b/e (barns per electron, equal to 10^{-28} m^2).

A formation with a high bulk density has a high number of electrons. It attenuates the gamma rays significantly, and hence a low gamma ray count rate is recorded at the sensors. A formation with a low bulk density has a low number of electrons. It attenuates the gamma rays less than a high density formation, and hence a higher gamma ray count rate is recorded at the sensors.

Sonic Log

Sonic logs measure how sound travels through rocks, and in particular provide information about porosity. With this method a probe sends out acoustic pulses which travel through the rock surrounding the well to the other end of the logging tool, and the velocity of sound in the rock is recorded (Fig. 16.18). This also indicates whether a liquid or gas phase occupies the pore spaces. The velocity is also dependent on how the rock is compacted, i.e. the pore distribution and the nature of the cements. The common sonic tools are BHC (borehole compensated sonic), LSS (long spaced sonic), array sonic/full waveform sonic and DSI (dipole shear imager). The velocity measured by the sonic log is however not a direct function of the

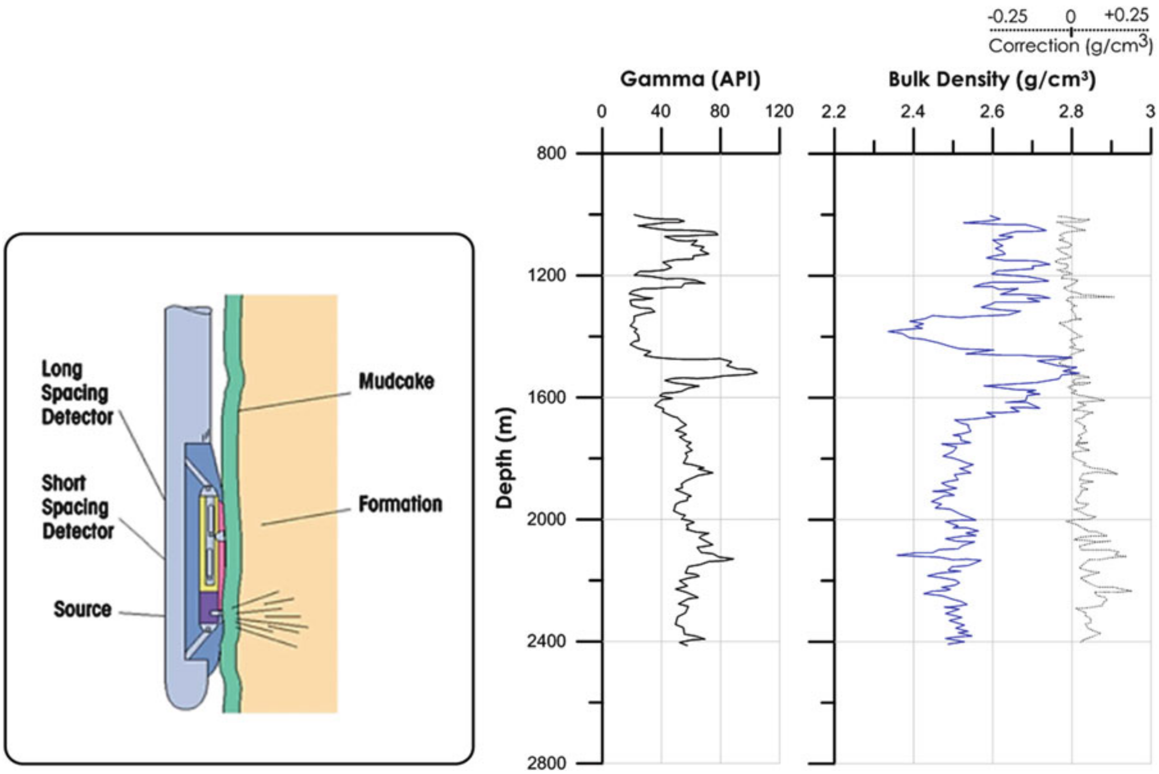

Fig. 16.17 The formation density tool and log response against shales and sandstones and their mixtures. The gamma ray log responses for the sequence are also presented

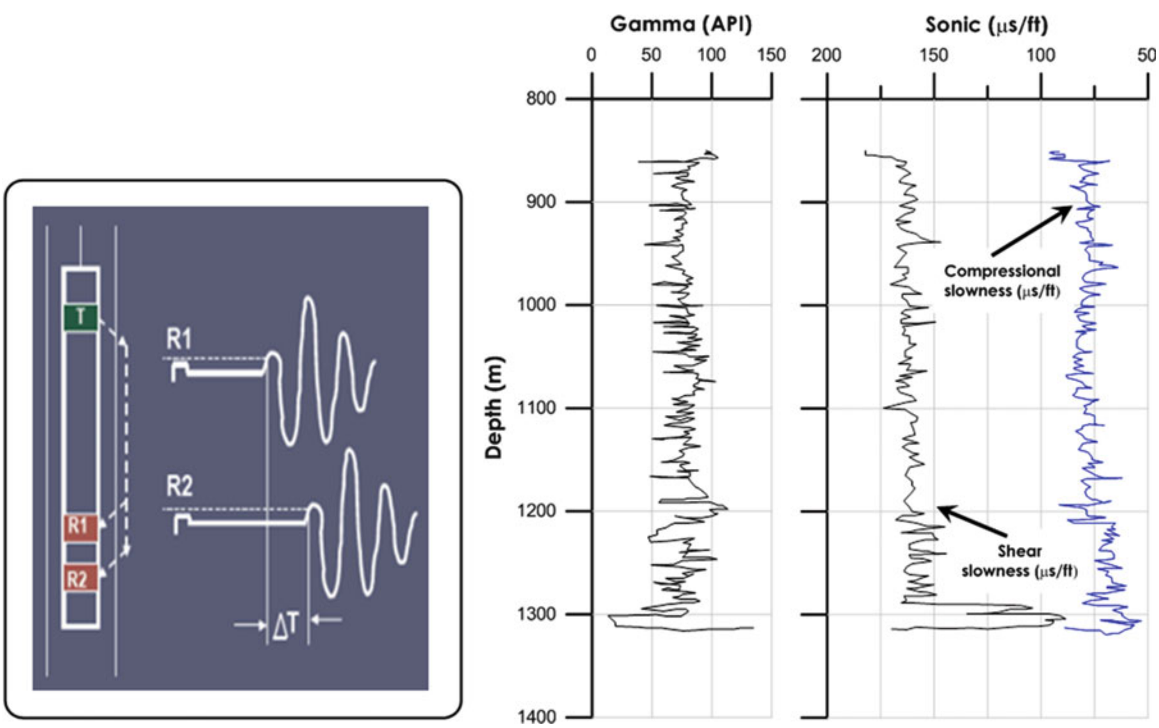

Fig. 16.18 The sonic tool and log responses against a sandstone-shale sequence. The gamma ray log responses for the sequence are also presented

porosity. The log record is usually presented as the Δt which is the inverse of velocity (i.e. slowness). This is called *interval transit time*, and is presented on the logs on a scale of 40–140 μs/ft (μs = 10^{-6} s) or μs/m. 100 μs/ft corresponds to 10,000 ft/s, or 3,048 m/s. The interval transit time (t) is the reciprocal of the sonic transit velocity (v).

Since the velocity of sound in water, which here means porewater, is considerably lower than it is in minerals and rocks, the measured velocity will be more or less inversely proportional to the rock porosity. In sandstones a small amount of cement (i.e. quartz cement) may produce a grain framework with high stiffness and velocity despite it retaining a relatively high porosity. In mudstones and shales the porosity and velocity vary greatly as a function of the clay mineralogy and the presence of carbonate or quartz cement.

Nuclear Magnetic Resonance (NMR)

NMR logging exploits the large magnetic moment of hydrogen, an element which is abundant in rocks in the form of water. The NMR signal amplitude is proportional to the quantity of hydrogen nuclei present in a formation and can be calibrated to give a value for porosity that is free from lithology effects (Fig. 16.19). A petrophysicist can also analyse the *rate of decay* of the NMR signal amplitude to obtain information on the permeability of the formation. Using NMR logs one can distinguish between free water in the pore space and H_2O and OH groups in minerals. Also bound water on mineral surfaces has a different NMR signature (T_2 distribution). The T_2 distribution has several petrophysical applications:

- T_2 distribution mimics pore-size distribution in water-saturated rock.

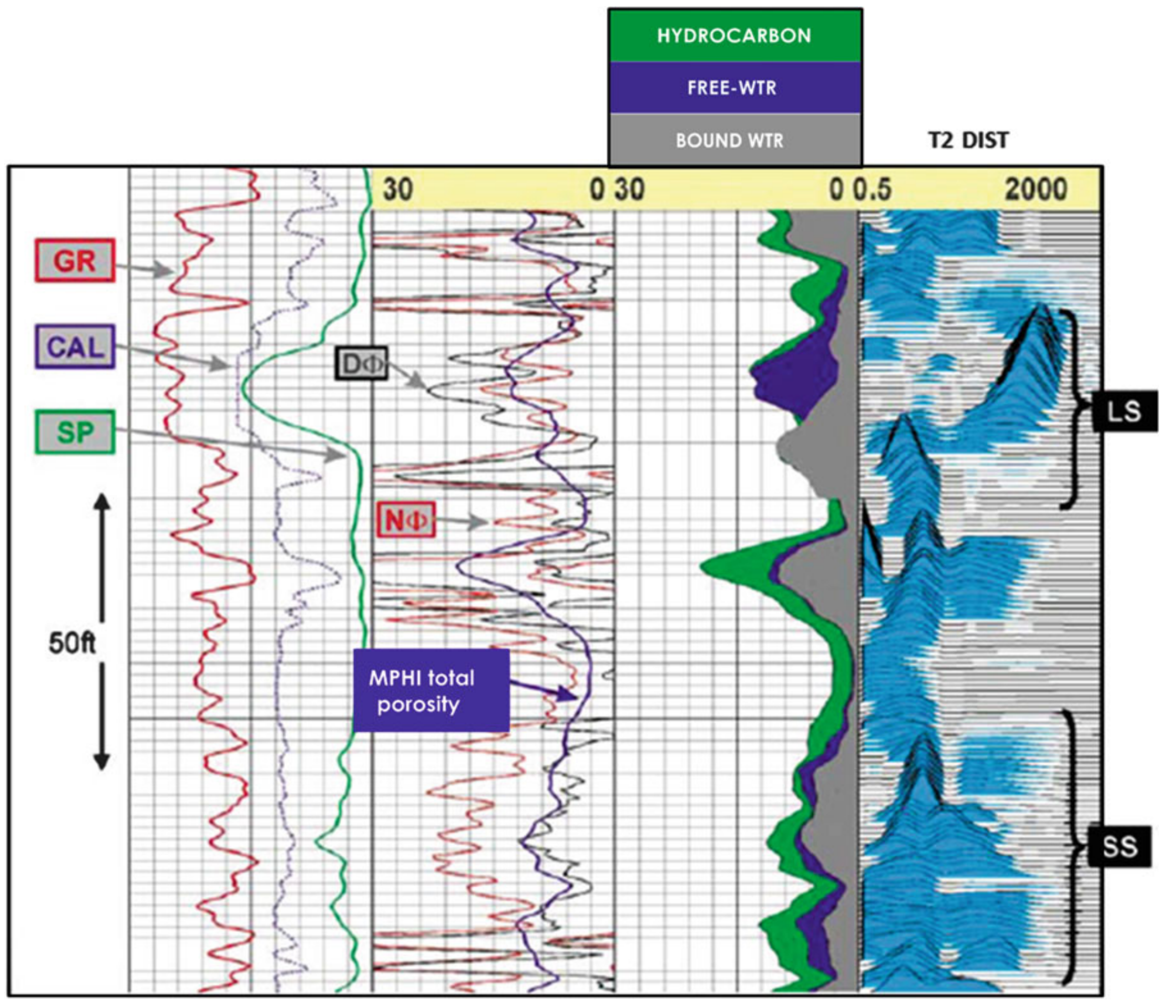

Fig. 16.19 A comparison of NMR total porosity (MPHI) and Neutron (Nϕ) and Density (Dϕ) porosities. Also shows T_2 distributions (NMR response), Gamma Ray, Caliper and SP logs. (Adapted from Coates et al. 1999)

- The area under the distribution curve equals NMR porosity.
- Permeability is estimated from the logarithmic-mean T_2 and NMR porosity.
- Empirically derived cutoffs separate the T_2 distribution into areas equal to free-fluid porosity and irreducible water porosity.

16.5.5.2 Uses of Porosity Logs

The main use of porosity logs is to provide porosity information. In combination with sonic and density logs, the important applications are *compaction trend and uplift estimation*, *overpressure detection*, *seismic data calibration* and *synthetic seismogram* generation. Furthermore, the combination of density and neutron logs give the best ways of identifying lithologies and detecting gas-bearing zones. Numerous uses of porosity logs are given below:

Porosity Estimation

When using a single porosity log, lithology must be specified through the choice of a matrix value, to avoid ambiguity in calculating porosity. Combinations of porosity logs may unravel complex matrix (e.g. quartz, calcite, dolomite) and fluid (e.g. brine, oil, gas) compositions, providing a more accurate porosity determination.

Porosity from Neutron Log

The neutron tool is sensitive to the amount of hydrogen ions in the formation and to a less extent also other elements. It is assumed that the contribution to the measurement by elements other than hydrogen is negligible, and that the contribution to the measurement from hydrogen comes entirely from the fluids fully occupying the pore space. However, in real rocks, elements other than hydrogen that exist in the rock matrix do contribute to the measurement, and hydrogen is also present in the matrix itself (e.g. bound water in shales). The problem is partially overcome by calibrating the tool against *limestone*. Pure limestone saturated with freshwater is used for calibration because it contains no elements which contribute significantly to the neutron measurements other than hydrogen. Therefore, the porosities that are read by the tool are accurate in limestones containing freshwater. The porosities that are read by the tool in other lithologies or with other fluids need to be corrected by a chart given in Fig. 16.20.

Porosity from Density Log

The bulk density log (ρ_{log}) measures the combined effects of the fluid density (ρ_{fluid}) and the density of the solid phase (ρ_{matrix}) and is used to compute density porosity (ϕ_D) using the following relation:

$$\phi_D = \left(\rho_{matrix} - \rho_{log}\right) / \left(\rho_{matrix} - \rho_{fluid}\right) \qquad (16.6)$$

The value of the matrix density taken depends upon the lithology of the target zone. The most common reservoir rocks are sandstone ($\rho_{matrix} = 2.65$ g/cm^3), limestone ($\rho_{matrix} = 2.71$ g/cm^3) and dolomite ($\rho_{matrix} = 2.87$ g/cm^3). Clay minerals have varied grain densities (Table 16.5). The input of fluid density (ρ_{fluid}) is usually that of formation brine (1.025 g/cm^3). The porosity may also be in error if the fluid density

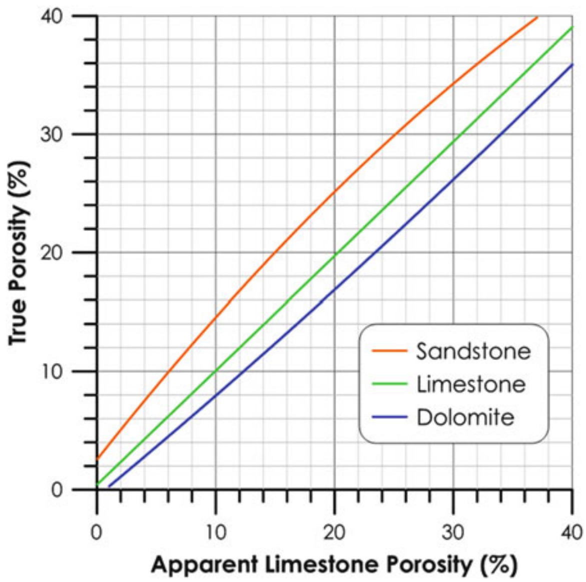

Fig. 16.20 Correction chart for obtaining porosity values for lithologies other than limestone (re-drawn, courtesy of Schlumberger)

Table 16.5 Grain (matrix) densities of some common rock-forming minerals

Mineral	Grain density (g/cm^3)	Mineral	Grain density (g/cm^3)
Quartz	2.65	Halite[a]	2.16
Calcite	2.71	Gypsum[a]	2.30
Dolomite	2.87	Anhydrite[a]	2.96
Biotite	2.90	Carnalite[a]	1.61
Chlorite	2.80	Sylvite[a]	1.99
Illite	2.66	Polyhalite[a]	2.78
Kaolinite	2.594	Glauconite	2.30
Muscovite	2.83	Kainite	2.13

[a]Evaporites

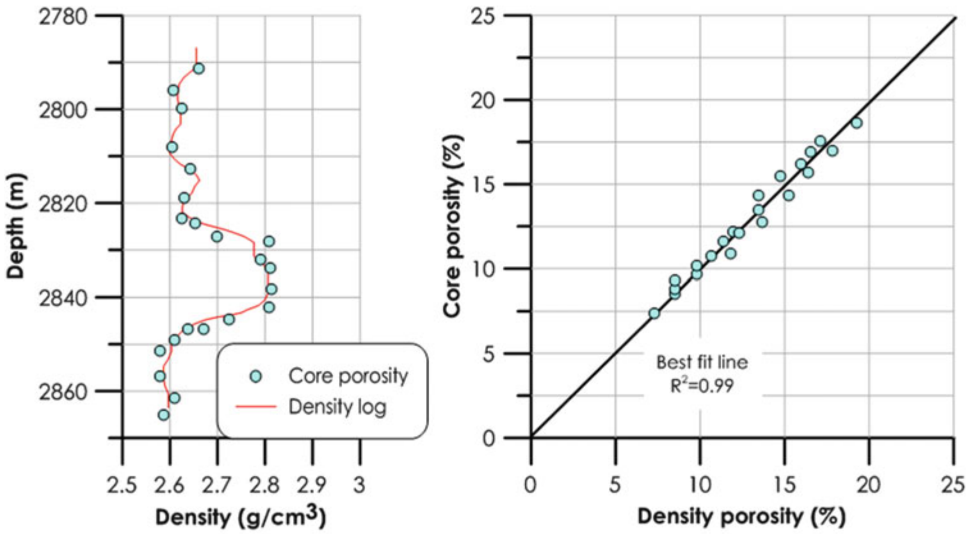

Fig. 16.21 Calibration of the density porosity (in %) calculated from formation density log (in g/cm^3) against core porosities (in %) measured in the laboratory

is misjudged. If oil or gas is present in the formation, porosities can be overestimated by the density log. Remember that the tool measures the invaded zone, so the relevant fluid is the mud filtrate in most circumstances. If available, the fluid densities should be corrected to borehole temperature conditions.

The most accurate porosity determinations are obtained from laboratory measurements on cores and so core data is used to provide accurate matrix densities for particular intervals. If there is a database of core porosities for a given well, it is often advantageous to plot the core porosity against the density log derived porosity (Fig. 16.21).

Porosity from Neutron and Density Combination

The combination of density and neutron logs is also used to determine porosity that is largely free of lithology effects. Both porosity logs record apparent porosities that are only true when the zone lithologies match with predicted lithologies in porosity calculations. By averaging the apparent neutron and density porosities of a zone, effects of lithologies can cancel out. The true porosity therefore is estimated either by taking an average of the two log readings or by applying the equation:

$$\phi = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}} \qquad (16.7)$$

where ϕ_N and ϕ_D are neutron and density porosities. It has been suggested that the square-root equation is preferable as a means of suppressing the effects of any residual gas in the flushed zone.

Porosity from Sonic Logs

The velocity of elastic waves through a given lithology is a function of porosity. Wyllie proposed a simple mixing equation to describe this behaviour and called it the *time average equation*. It can be written in terms of velocity

$$\phi_s = \frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_f - \Delta t_{matrix}} \qquad (16.8)$$

where Δt_{log} is the transit time in the formation of interest, Δt_f is that through 100% of the pore fluid and Δt_{matrix} is that through 100% of the rock matrix (solid mineral grains), ϕ_s is the sonic porosity. A list of input values to these equations for common lithologies and fluids is given in Table 16.6.

Lithology Discrimination

Lithology identification using the neutron-density log combination is a hugely important technique, and together with the litho-density log forms the best downhole lithology identification technique available. The measured neutron porosity in shales is considerably higher than the measured neutron porosity in

Table 16.6 Values for Δt and P-wave velocities for use in Wyllie's equation

Material	Δt (μs/ft)	V (ft/s)	V (m/s)
Compact sandstone	55.6–51.3	18,000–19,500	5,490–5,950
Limestone	47.6–43.5	21,000–23,000	6,400–7,010
Dolomite	43.5–38.5	23,000–26,000	7,010–7,920
Anhydrite	50.0	20,000	6,096
Halite	66.7	15,000	4,572
Shale	170–60	5,880–16,660	1,790–5,805
Bituminous coal	140–100	7,140–10,000	2,180–3,050
Lignite	180–140	5,560–7,140	1,690–2,180
Casing	57.1	17,500	5,334
Water: 200,000 ppm, 15 psi	180.5	5,540	1,690
Water: 150,000 ppm, 15 psi	186.0	5,380	1,640
Water: 100,000 ppm, 15 psi	192.3	5,200	1,580
Oil	238	4,200	1,280
Methane, 15 psi	626	1,600	490

carbonate or sandstone. This unrealistically high porosity is a good indicator of shale, and can become diagnostic when combined with the gamma ray log. One can see from the neutron-density crossplot that there will be a separation of the density and the neutron logs for sandstone and dolomite, but no separation for limestone (Fig. 16.22). The sandstone separation is called negative and the dolomite separation, which is in the other direction and slightly larger, is called positive. If shale is present in the formation, the neutron log reads much higher porosities and gives a large positive separation. If the shale volume decreases due to the intermixture of sandstone, the large positive separation decreases, crosses over and becomes eventually the small negative separation associated with pure sandstone. Thus, a sequence of clearly defined sand and shale formations shows switching between positive and negative separations in a neutron-density crossplot.

Detection of Gas

The rules governing the relationship between neutron log porosity and the true porosity in clean formations are valid when either water or oil fills the pores (the two fluids have essentially the same hydrogen index, Rider 2004). However, hydrocarbon gas has a much lower hydrocarbon index resulting from its low density, and its presence will give rise to *underestimations* in porosity. On the neutron-density combination, gas stands out very distinctly, giving a large negative separation (Fig. 16.23).

Detection of Overpressure

Sonic logs can be used to detect overpressured zones in a well. An increase in pore pressures causes a clear drop in sonic velocity (i.e. an increase in sonic travel time). Fluid overpressure works against any compaction trend caused by the overburden pressure. Hence, it is likely that overpressured zones will retain a greater porosity than normally pressured zones. If a normal compaction or no compaction is observed in a shale over some depth interval, and below it the bulk density begins to decrease (or the derived porosity begins to increase) without change in lithology, it is likely that one has entered a zone of overpressured fluids. In this zone the overpressured fluids keep the porosity open, stopping any compaction trend and reversing it (Fig. 16.24).

Uplift Estimation

As sediments become compacted, the velocity of elastic waves through them increases. If one plots the interval transit time on a logarithmic scale against depth on a linear scale, a straight line relationship emerges. This is called *compaction trend*. Compaction trends are constructed for single lithologies, comparing the same stratigraphic interval at different depths. It is possible to estimate the amount of erosion at unconformities or the amount of uplift from these trends. This is because compaction is generally accompanied by diagenetic changes which do not alter after uplift. Hence *the compaction of a sediment represents its deepest burial*. Figure 16.25 compares the compaction trend for the same lithology in the same stratigraphic interval in one well with that in another well. The data from the well represented by the circles shows the interval to have been uplifted by 800 m relative to the other well because it has lower interval transit times (means more compact) but occurs at a shallower depth.

Seismic Data Calibration and Synthetic Seismogram Generation

A sonic log in a well located on a seismic line or in a 3D survey enables the log data to be used to calibrate

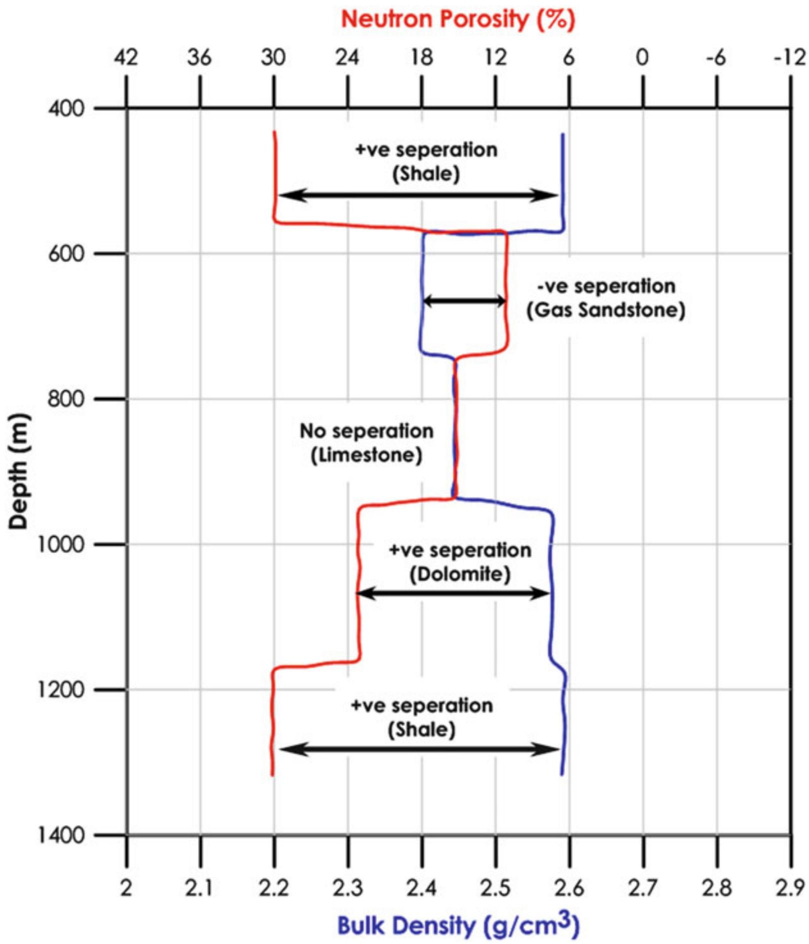

Fig. 16.22 The density and neutron log responses for shale, sandstone, limestone, dolomite sequence on a compatible scale. No separation observed in limestone but a large positive separation occurs in shale compared to dolomite. Negative separation against sandstone may indicate gas. (Modified from Rider 2004)

and check the seismic data. In general, the sonic log resolution is about 60 cm compared to seismic 10–50 m. Therefore, the sonic log must be averaged when comparing it with seismic measurement. However, the much higher resolution of the sonic log may enable the log information to resolve indications of beds that are just beyond the resolution of the seismic technique. Note that the sonic log gives a one-way travel time, and the seismic technique gives a two-way travel time.

A synthetic seismogram is a seismic trace that has been constructed from various parameters obtainable from log information. It represents the seismic trace that should be observed with the seismic method at the well location. It is useful to compare such a synthetic seismogram with the real seismic trace measured at the well location to improve the picking of seismic horizons, and to improve the accuracy and resolution of formations of interest. It should be remembered that the observed seismic trace is primarily a record of the ability of interfaces between formations to reflect elastic waves. This ability is called the reflection coefficient *R*. The reflection coefficient depends upon the properties of the rock either side of the interface, and in particular on its acoustic impedance. The acoustic impedance is the product of the seismic velocity and the density of the rock. Thus, if we can derive the density and seismic velocity of a set of formations from logs, we can produce a synthetic seismogram (Fig. 16.26).

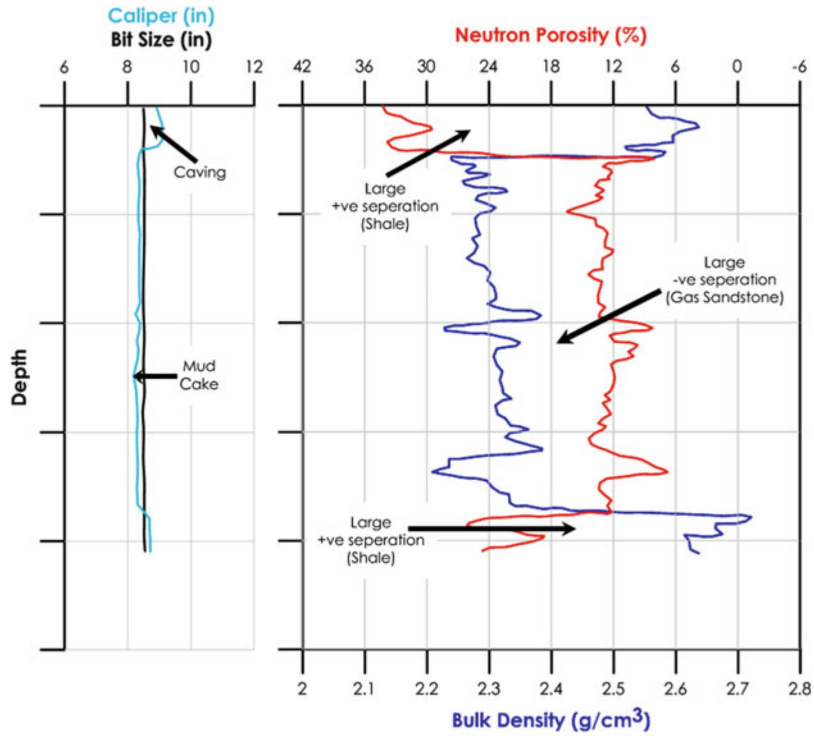

Fig. 16.23 The gas effect in the neutron-density crossplot shows large negative separation in reservoir zone. On the other hand large positive separations occur in shales (top and bottom of the reservoir). (Modified from Rider 2004)

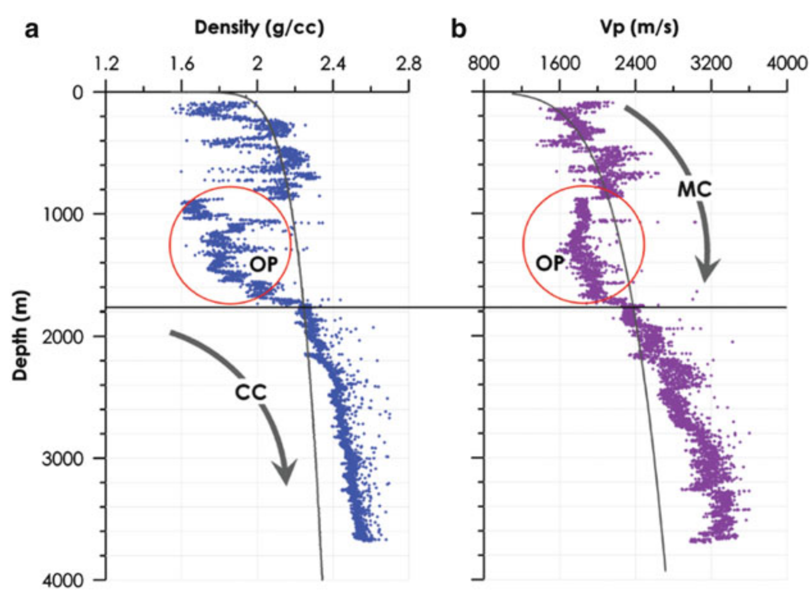

Fig. 16.24 Recognition of shale compaction and overpressure in shale sequences using the formation density and sonic logs. (Adapted from Mondol et al. 2008)

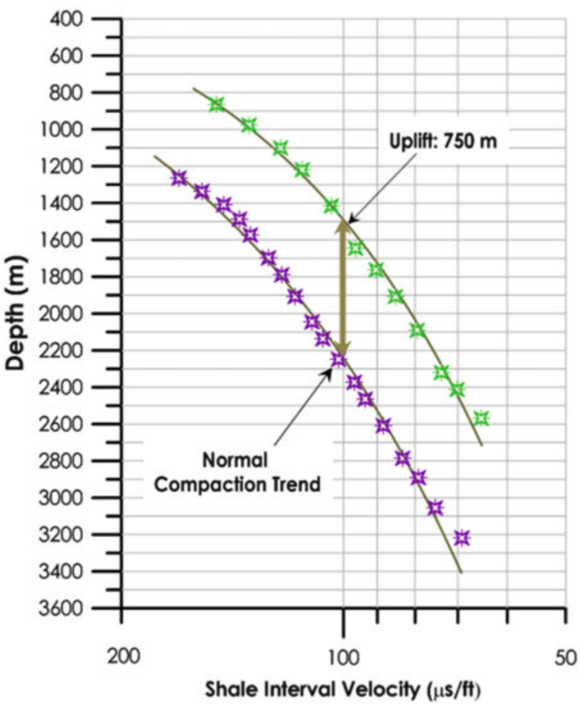

Fig. 16.25 Estimation of uplift and erosion from sonic log derived shale compaction trends

16.5.5.3 Uncertainties of Porosity Logs

Enlarged and rough boreholes, formation fracture, gas in the borehole and formation, or improper centralisation can produce signal attenuation in porosity log measurements resulting in higher porosity values. In rough holes or in heavy drilling muds, the density data might be invalid. Porosity calculated from density and sonic depends on the choice of matrix density and matrix transit time, which varies with lithology. Porosity calculations for unconsolidated formations may yield porosity values higher than the actual values when using the Wyllie equation (Wyllie et al. 1956). Porosity calculated from density depends on the choice of fluid density, which varies with fluid type and salinity. Porosity calculated in gas-bearing zones will be higher than the actual values because the traveltime in gas is higher than in water. Presence of gas (light HC) in the pore space causes density-derived porosity to be more than the actual porosity. If the actual lithology is sandstone, the measured neutron porosity is less than the actual porosity. If the actual lithology is dolomite, the log porosity is greater than the actual porosity. If gas is present in the formation, porosities can be overestimated (Fig. 16.27).

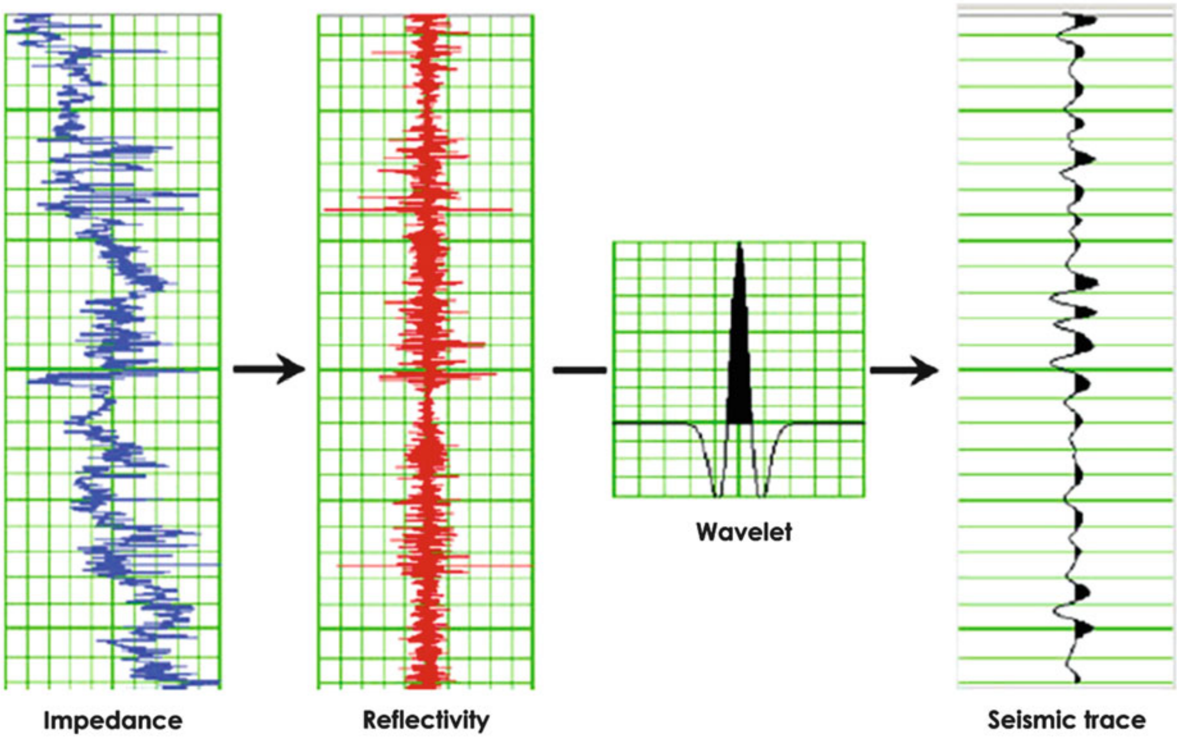

Fig. 16.26 Synthetic seismic trace constructed from impedance and reflectivity convolved with wavelet. (Adapted from Mondol et al. 2010)

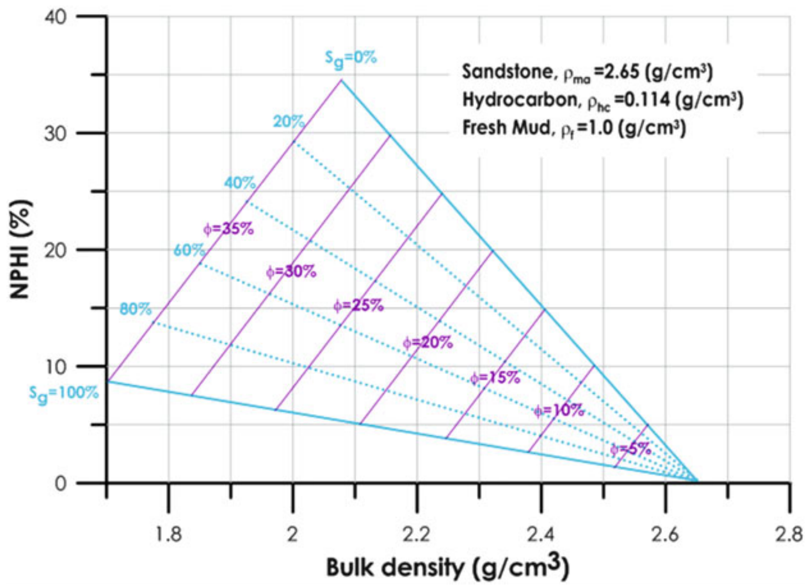

Fig. 16.27 Effect of gas on measured neutron porosity (NPHI) and bulk density logs. (Re-drawn, courtesy of Schlumberger)

16.5.6 Photoelectric Factor/Litho-density Log

16.5.6.1 Generalities and Basic Principles

The photoelectric factor (PEF) or litho-density log is a new form of the density log with added features. The tool is physically very similar to the density tool but it has enhanced detectors, and the distance between the long spacing and the short spacing detectors has been decreased. This decrease has increased the vertical resolution of the tool and improved its overall counting accuracy. The photoelectric tool has a caesium-137 source emitting gamma rays at 0.662 MeV. The more efficient detectors in the litho-density tool have the ability to recognise and count separately gamma rays which have high (0.25–0.662 MeV) and low (0.04–0.0 MeV) energies. The high energy gamma rays are those that are undergoing *Compton scattering*. The low energy gamma rays are those that are undergoing *photoelectric absorption*. The probability that a gamma ray is adsorbed by the process of photoelectric absorption depends upon the characteristic photoelectric cross-section of the process (σ_e). Characteristic photoelectric cross-sections are measured in barns, where 1 barn $= 10^{-24}$ cm^2. A specific photoelectric absorption index P_e is defined with the relationship

$$Pe \equiv \frac{1}{K}\frac{\sigma_e}{Z} \tag{16.9}$$

where Pe is the photoelectric absorption index (barns/electron), σe is the photoelectric cross-section (barns), Z is the atomic number (number of electrons) and K is a coefficient dependent upon the energy at which the photoelectric absorption is observed (no units). A log scale running from 0 to 10 barns/electron is most often used (Fig. 16.28). The photoelectric log values of common minerals and fluids are given in Table 16.7.

16.5.6.2 Uses of Photoelectric/Litho-density Log

The PEF/litho-density log is one of the most useful logs for lithology discrimination. This is simply because the tool is sensitive only to the mean atomic number of the formation, and at the same time is insensitive to changes in porosity and fluid saturation in the rock. Hence, the absolute P_e value may often be used to indicate directly the presence of a given lithology, which may then be checked against the other tool readings for consistency. Uses of PEF to discriminate lithologies are shown below:

Identification of Reservoir Rocks

The addition of the photoelectric log to the gamma ray and neutron-density logs provides both additional

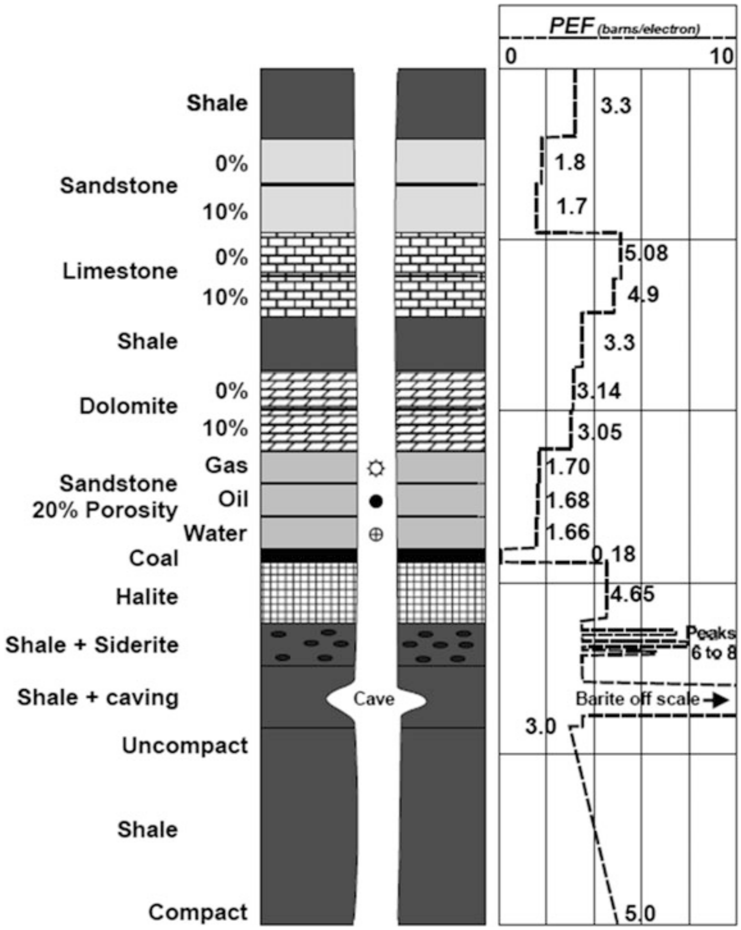

Fig. 16.28 Measurements of the photoelectric (litho-density) log for common lithologies. (Modified from Rider 2004)

validation of simple lithology picks and the resolution of ambiguities in interpretation of "complex" (multi-mineral) lithologies. The generalised expectations of log patterns for shales and endmember reservoir lithologies of limestone, dolomite and sandstone are shown in Fig. 16.29. In the examination of the neutron-density log overlay, dolomites and siliceous rocks (either sandstones or cherts) can be recognised by the curve separations. However, the close overlay of the two could be caused either by a limestone or a cherty dolomite (or a cherty dolomitic limestone!). The inclusion of the photoelectric index can be used to choose between these alternatives. Similarly, a dolomite reading on the photoelectric index curve could also be caused by a cherty or sandy limestone. The simultaneous consideration of the neutron-density log overlay resolves the more likely of these two interpretations.

If there is a mixture of two mineralogies, for example a sandy limestone, a crossplot technique or a simple mixing rule can be applied to calculate the relative proportions of the two mineralogies. In the crossplot technique, the *Pe* value is plotted on the *x*-axis against bulk density on the *y*-axis. The point lies between lines that indicate the relative proportions of three lithologies (sandstone, dolomite and limestone).

Evaporite Identification

The geological interpretation of log overlays is easily extended to sedimentary lithologies other than the common reservoir lithologies of sandstone, limestone and dolomite. The common evaporite minerals of gypsum, anhydrite and halite each have highly distinctive PEF properties as shown in Fig. 16.29. Halite and anhydrite have markedly low and high bulk densities,

Table 16.7 Common photoelectric log values (adapted from Rider 2004)

	P_e	ρ_b
Quartz	1.81	2.65
K-feldspar	2.86	2.62
Calcite	5.08	2.71
Dolomite	3.14	2.87
Shale	3.42	2.65
Shaly sand	2.70	2.41
Muscovite	2.40	3.29
Biotite	6.30	3.34
Glauconite	5.32	3.95
Halite	4.65	2.07
Anhydrite	5.10	2.98
Gypsum	4.00	2.35
Coal Anthracite	0.16	1.75
Coal Bituminous	0.18	1.47
Coal Lignite	0.20	1.19
Barite	266.8	4.50
Pyrite	16.97	5.00
Hematite	21.48	5.24
Magnetite	22.24	5.18
Pure water	0.358	1.00
Salt water (NaCl 120,000 ppm)	0.81	1.19
Oil	0.13	0.97
Methane	0.095	0.25

respectively, while the very high neutron porosity of gypsum is caused by hydrogen in its water of crystallisation.

Coal Identification

In combination with density and neutron logs, PEF can be useful to identify coal (Fig. 16.29). Clastic successions containing coals were commonly developed in deltaic environments with shales, siltstones and sandstones, as well as occasional ironstones (typically siderite). The clay mineralogy of the finer-grained rocks is quite variable and can show elevated contents of kaolinite, particularly in palaeosols. The PEF response of coals varies according to their rank (0.20 for lignite, 0.17 for bitumin and 0.16 for anthracite).

16.5.6.3 Uncertainties of Photoelectric/ Litho-density Log

Most drilling fluids have very low PEF values. When this information is combined with the fact that the litho-density tool is pad-mounted and pressed against the borehole wall, one can see that most types of drilling mud will not have a great effect on the PEF measurements. The exception is barite which has a huge PEF value and will swamp all other log responses if the tool sees barite drilling mud. Therefore, in practice the PEF log is not used in holes drilled with barite mud.

16.5.7 Resistivity and Conductivity Logs

16.5.7.1 Generalities and Basic Principles

Resistivity is a fundamental material property that represents how strongly a material opposes the flow of electric current (Fig. 16.30). Most rock-forming minerals are essentially insulators, while their enclosed fluids are conductors. Almost all conduction takes place through the liquid phase, and the resistance therefore depends primarily on the pore fluid and its salt content. Hydrocarbon fluids are an exception, because they are almost infinitely resistive. When a formation is porous and contains salty water, the overall resistivity will be low. When the formation contains hydrocarbon, or contains very low porosity, its resistivity will be high. Resistivity is also a function of the amount of porewater relative to rock volume (hence porosity) and the distribution of pores in the rock (permeability).

The resistivity log must run in holes containing electrically conductive mud. Each of the electric log measurements depends on the degree to which drilling mud invades the formation, because this will influence the electrical properties surrounding the borehole (Fig. 16.31). The resistivity or conductivity measurements are, of course, measuring the same property of the rock, and can be interconverted by Resistivity = 1/Conductivity. The resistivity units are ohm-m^2/m or simply ohm-m (Ω m). The resistivity of a formation depends on the resistivity of the formation water, the amount of water present, and the structure and geometry of the pores, and can be expressed by

$$R = \frac{r \times A}{L} \tag{16.10}$$

where R is the resistivity (ohm-m), r is the resistance (ohms), A is the cross-sectional area (m^2) and L is the length (m). Most formations have resistivities in the range 0.2 to 1,000 ohm-m. Resistivities higher than

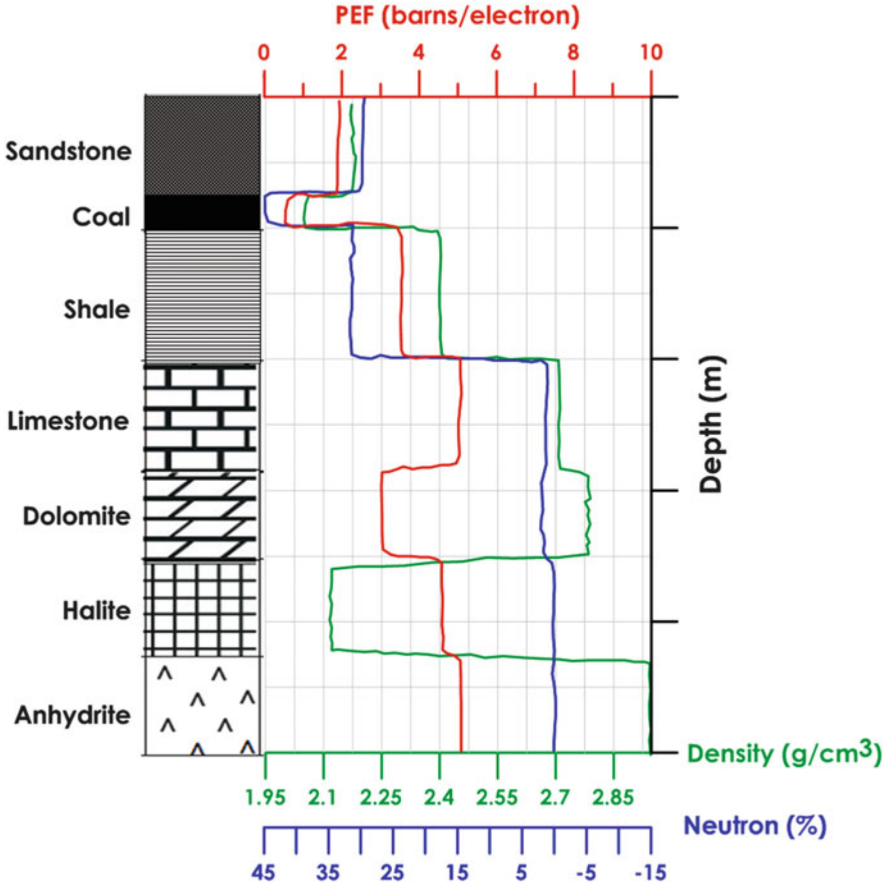

Fig. 16.29 A comparison of litho-density (photoelectric), density and neutron log responses to identify reservoir rocks (sandstone, limestone, dolomite), evaporate (halite and anhydrite) and coal

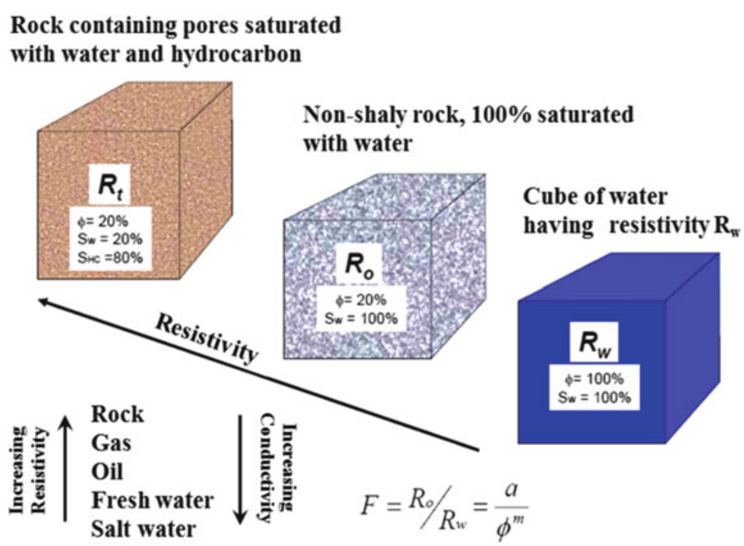

Fig. 16.30 A general trend of electrical resistivity of reservoir rocks and fluids

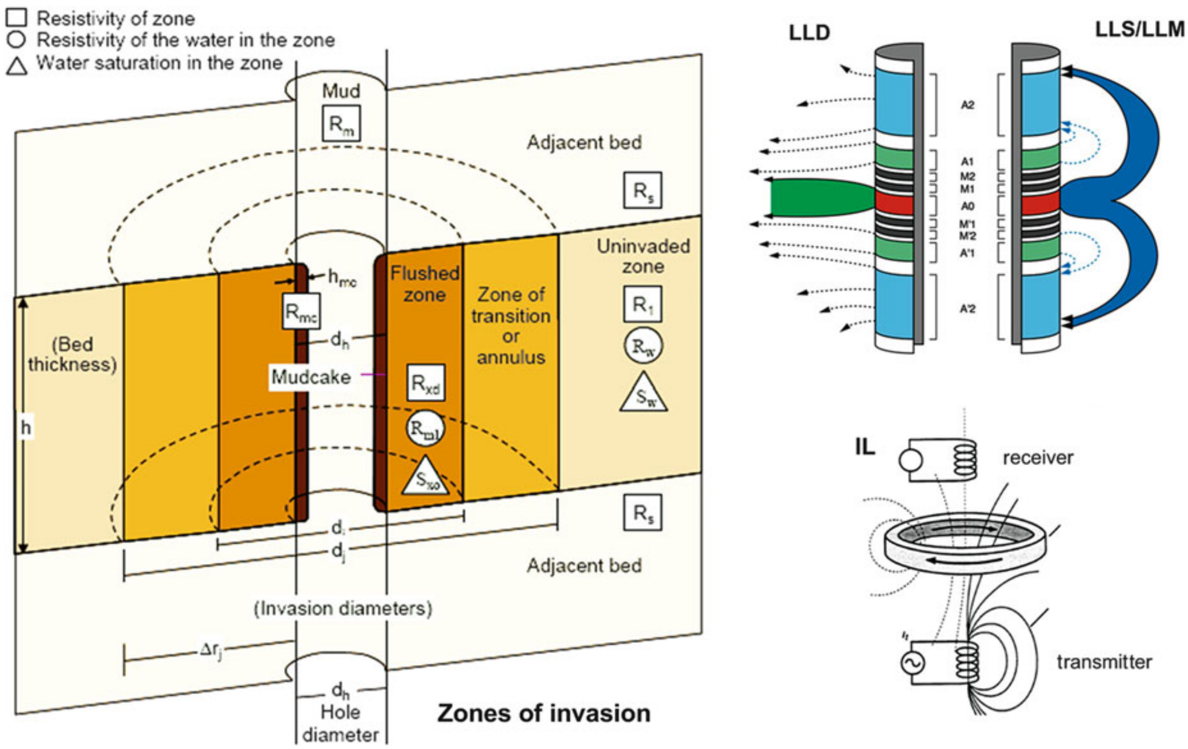

Fig. 16.31 The borehole environment showing zones of invasion of drilling fluids and measured resistivity in different zones (*left*, courtesy of Schlumberger). Schematic electrode disposition in several body-mounted, focused laterologs (e.g. LLD, LLS, LLM) and induction log (IL) tools (*right*, courtesy of Schlumberger)

1,000 ohm-m are uncommon in most permeable formations but are observed in impermeable, low porosity formations such as evaporites. A few low porosity hydrocarbon-bearing formations with almost no formation water can have resistivities as high as 20,000 ohm-m. Because resistivities cannot be read accurately over the entire measurement range when displayed on a linear scale, all resistivity logs are presented on logarithmic grids (Fig. 16.32).

Resistivity and Conductivity Tools

To measure electrical rock properties, there are two main types of logging tool available: one measures resistivity (resistivity tools) and the other measures conductivity (induction tools). Formation resistivities are measured either by passing a known current through the formation and measuring the electrical potential (electrode or galvanic devices) or by inducing a current distribution in the formation and measuring its magnitude (induction devices). An electric current can pass through a formation because it contains water with enough dissolved ions to be conductive. With a few rare exceptions, such as clay minerals, metallic sulphides and graphite, rock matrix is a good electrical conductor. The resistivity and conductivity tools have many varieties that are commonly used to investigate resistivity in different zones around the borehole (Table 16.8).

Laterologs (LLS, LLM and LLD) contain three electrodes on the tool – a central electrode and two guard electrodes to focus current (Fig. 16.31). Current in the guards is adjusted to maintain the same potential as the centre electrode. The lack of potential difference between electrodes means that current flows outwards horizontally. In an induction tool (IL), the vertical component of the magnetic field from the transmitting coil induces ground loop currents. The current loops in the conductive formation produce an alternating magnetic field detected by the receiver coil (Fig. 16.31).

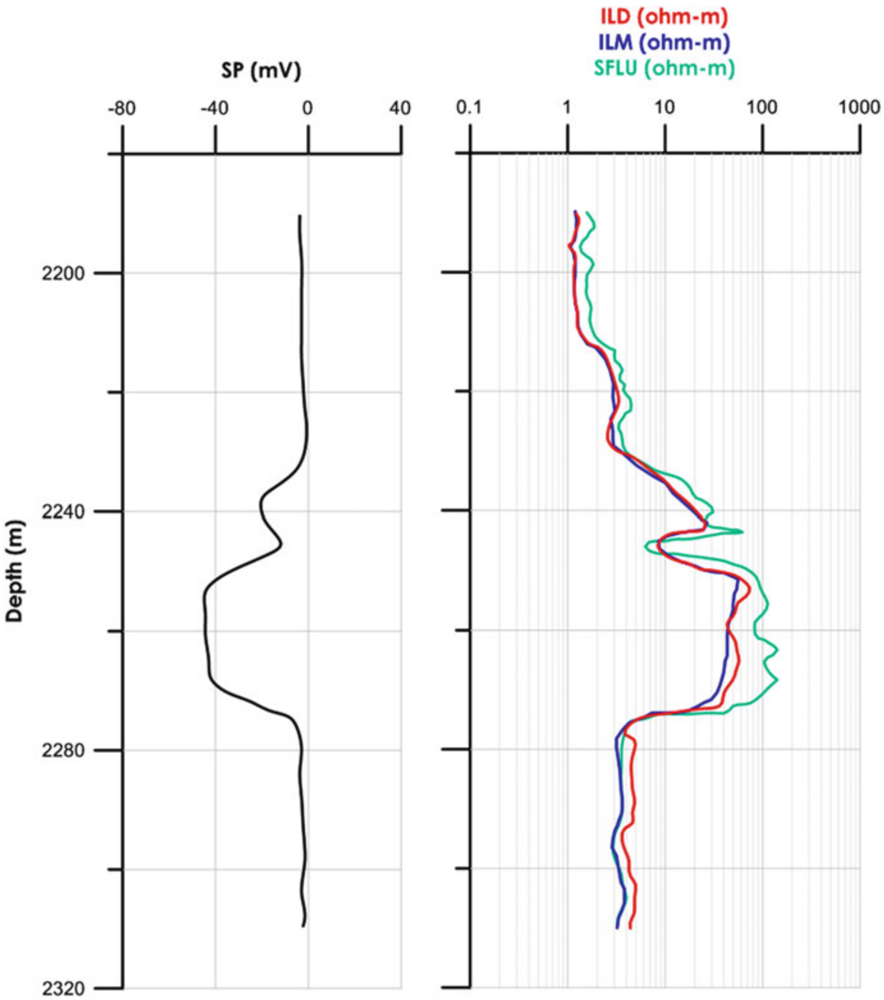

Fig. 16.32 Example of dual (ILM and ILD) induction logs through a hydrocarbon zone. The drilling mud is freshwater-based ($R_{mf} > R_w$) where muds invade a hydrocarbon-bearing formation (e.g. Sw <60%). There is high resistivity in the flushed zone (R_{xo}) due to freshwater as well as residual hydrocarbon, high resistivity in the invaded zone (R_i), and a very high resistivity in the uninvaded hydrocarbon zone (R_t)

Table 16.8 Types of resistivity and conductivity logging tools

Flushed zone (R_{xo})	Invaded zone (R_i)	Uninvaded zone (R_t)
Microlog (ML)	Short Normal (SN)	Long Normal (LN)
Microlaterolog (MLL)	Medium Induction Log (ILM)	Deep Induction Log (ILD)
Proximity log (PL)	Shallow Laterolog (LLS)	Deep Laterolog (LLD)
Micro Spherically Focused Log (MSFL)	Spherically Focused Log (SFL)	

16.5.7.2 Uses of Resistivity and Conductivity Logs

Resistivity/conductivity measurements have immense value for detection and quantitative evaluation of hydrocarbon productive zones and correlation of geological strata. High resistivity values may indicate a hydrocarbon-bearing formation. Oil and gas have far higher resistivity than water, so resistivity logs can be used to locate the contacts between oil/water (OWC), gas/water (GWC) and gas/oil (GOC) in the reservoirs. It also helps to determine hydrocarbon saturation. Once we know the resistivity of the drilling mud, the porosity of the rock can be calculated from the resistivity of that part of the rock which has been invaded by the mud. In addition, resistivity log is also useful to identify source rocks.

Detection of Hydrocarbon

By far the most important use of resistivity logs is the determination of hydrocarbon-bearing versus water-bearing zones. Because the rock's matrix or grains are non-conductive and any hydrocarbons in the pores are also non-conductive, the ability of the rock to transmit a current is almost entirely a function of formation brine in the pores. As the hydrocarbon saturation of the pores increases (causing the water saturation to decrease), the formation's resistivity increases. As the salinity of the water in the pores decreases (as R_w increases), the rock's resistivity also increases.

When sufficient quantities of hydrocarbons are present, the deep resistivity (ILD) will show extremely high resistivity because of the high saturation in hydrocarbons (Fig. 16.32). When hydrocarbons are present, the borehole environment becomes three phase and much more complex compared to a water zone. The freshwater mud will replace the hydrocarbons immediately around the borehole, essentially replacing them through the flushed and invaded zones, while the original hydrocarbon saturation is only found in the uninvaded (virgin) zone.

Determination of Water Saturation (S_w)

Archie's law laid the foundation for modern well log interpretation as it relates borehole electrical resistivity measurements to hydrocarbon saturations. It is a purely empirical law attempting to describe flow in clean, consolidated sandstones, with varying intergranular porosity. Archie's law relates the *in-situ* electrical resistivity of a rock to its porosity and brine saturation and is expressed by the following equation:

$$R_t = a\phi^{-m}S_w^{-n}R_w \tag{16.11}$$

$$S_w \left(\frac{a \times R_w}{R_t \times \phi^m}\right)^{1/n} \tag{16.12}$$

where S_w is the water saturation, a is the tortuosity factor, m is the cementation exponent (usually in the range 1.8–2.0 for sandstones), n is the saturation exponent (usually close to 2), R_w is the resistivity of formation water, ϕ is the porosity and R_t is the true formation resistivity as derived from a deep resistivity log (e.g. ILD). A geoscientist, by knowing (or determining) several parameters (F, a, m, and n described in the following paragraphs), and by determining from logs the porosity (ϕ), formation water resistivity (R_w) and true formation resistivity (R_t), can determine the formation's water saturation (S_w) using the Archie equation. Table 16.9 summarises the sources of the parameters that go into the Archie's equation to calculate the S_w.

Table 16.9 Sources of data for calculation of water saturation by Archie's equation

Parameter	Source
R_t	Deep resistivity tool
R_w	SP log Calculated from water zone Measured on RFT (repeated formation tester) sample
ϕ	Neutron, density, sonic, NMR
F	Guessed
m	Measured in laboratory, Guessed
n	Measured in laboratory, Guessed

Formation resistivity factor (F) The bulk resistivity of a rock (R_0) saturated with a formation fluid of resistivity R_w is directly proportional to the resistivity of the fluid and can be expressed by the following equations

$$R_0 = FR_w \tag{16.13}$$

or

$$F = R_0/Rw \tag{16.14}$$

where F is the *formation resistivity factor* and describes the effect of the presence of the rock matrix. Note that the formation factor (F) has no units because of the ratio of two resistivities. It can be seen that $F = 1.00$ for a rock with 100% porosity, i.e. no matrix, just 100% fluid. If we take 100% fluid and slowly add grains of rock, the porosity decreases. However, the insulating grains of rock have negligible conductivity (infinite resistivity) compared to the conducting fluid. Hence, R_0 will increase, which implies that F is always greater than unity in a porous medium. In real rocks F varies between 20 and 500. It is a function of the porosity and permeability of the rock and is an expression of rock properties independent of the conductivity of the porewater. For sediments with a high primary porosity the formation factor will be an expression of the diagenetic alteration of the rock and the relationship can be expressed as

$$F = a/\phi^m \tag{16.15}$$

where ϕ is the porosity and m is the cementation exponent which varies from 1 for porous rock to 3 for very well cemented rock (average value is 2.0). a is a constant (tortuosity factor) which for carbonate rocks is about 1.0 depending on the permeability (or tortuosity).

Cementation exponent (m) The cementation exponent expresses how much the pore network increases the resistivity. The cementation exponent has been observed near 1.3 for unconsolidated sands, and is believed to increase with cementation. Common values for this cementation exponent for consolidated sandstones are $1.8 < m < 2.0$. In carbonates, the cementation exponent shows higher variance due to strong diagenetic affinity and complex pore structures. Values between 1.7 and 4.1 have been observed. The cementation exponent is usually assumed not to be dependent on temperature.

Tortuosity factor (a) The tortuosity factor is an important parameter of formation resistivity factor calculations in the Archie formula, which is used to predict water saturation. It is equal to the square root of tortuosity, is a function of the average angle of electrical movement with respect to the bulk fluid flow and cementation exponent (m) and is related to the flow area difference between pore throat and pore body.

Saturation exponent (n) The saturation exponent expresses the dependency on the presence of non-conductive fluid (hydrocarbons) in the pore-space, and is related to the wettability of the rock. Water-wet rocks will, for low water saturation values, maintain a continuous film along the pore walls making the rock conductive. Oil-wet rocks will have discontinuous droplets of water within the pore space, making the rock less conductive. The saturation exponent usually is fixed to values close to 2.

Resistivity-Derived Porosity

The minerals that make up the grains in the matrix of the rock, and the hydrocarbons in the pores of the rock, are non-conductive. Therefore, the ability of rock to transmit an electrical current is almost entirely the result of the water in the pore space. Thus, resistivity measurements can be used to determine porosity. Normally, measurements of a formation's resistivity close to the borehole (flushed zone, R_{xo}, or invaded zone, R_i) are used to determine porosity. When a porous, permeable, water-bearing formation is invaded by drilling fluid, formation water is displaced by mud filtrate. Porosity in a water-bearing formation can be related to shallow resistivity (R_{xo}) by the following equation:

$$\phi = \left(\frac{a \times R_{mf}}{R_{xo}}\right)^{1/m} \tag{16.16}$$

where ϕ is the formation porosity, R_{mf} is the resistivity of mud filtrate at formation temperature, R_{xo} is the flushed-zone resistivity, a is the tortuosity factor and m is the cementation exponent. In hydrocarbon-bearing zones, the shallow resistivity (R_{xo}) is affected by the unflushed residual hydrocarbons left by the invading mud filtrate. These residual hydrocarbons result in a value for shallow resistivity (R_{xo}) that is too high because hydrocarbons have a higher resistivity than formation water. Therefore, the calculated resistivity porosity in hydrocarbon-bearing zones is too low. To correct for residual hydrocarbons in the flushed zone, water saturation of the flushed zone (S_{xo}) must be known. Then, a formation's shallow resistivity (R_{xo}) can be related to porosity by the following ($S_{xo} < 1.0$):

$$\phi = \left[\frac{a}{S_{xo}^2} \times \frac{R_{mf}}{R_{xo}}\right]^{1/m} \tag{16.17}$$

Source Rock Investigations

A source rock can significantly influence the resistivity log, depending on the maturity of the organic content: it has little effect when immature, but causes a large effect when it is mature. A typical shale with matrix dominated by clay minerals and silts has a certain water-filled porosity, whereas typically 5–15% of the matrix of a source shale is comprised of organic matter. If the source rock is immature the pore space is filled with water, but if the source rock is mature, the pores contain both water and hydrocarbons and so give high resistivity values compared to the normal shale or immature source shale. The high resistivity anomaly is thus related to the degree of maturity of source rocks (Passey et al. 1990). A high resistivity in a shale interval can also be interpreted as carbonate-rich zones, or as highly compacted shales with very low porosity. If the hydrocarbon effect is to be highlighted, the resistivity log is crossplotted with either sonic or density logs (Fig. 16.33).

It is even possible to calculate the amount of TOC in a source rock from the resistivity and sonic logs.

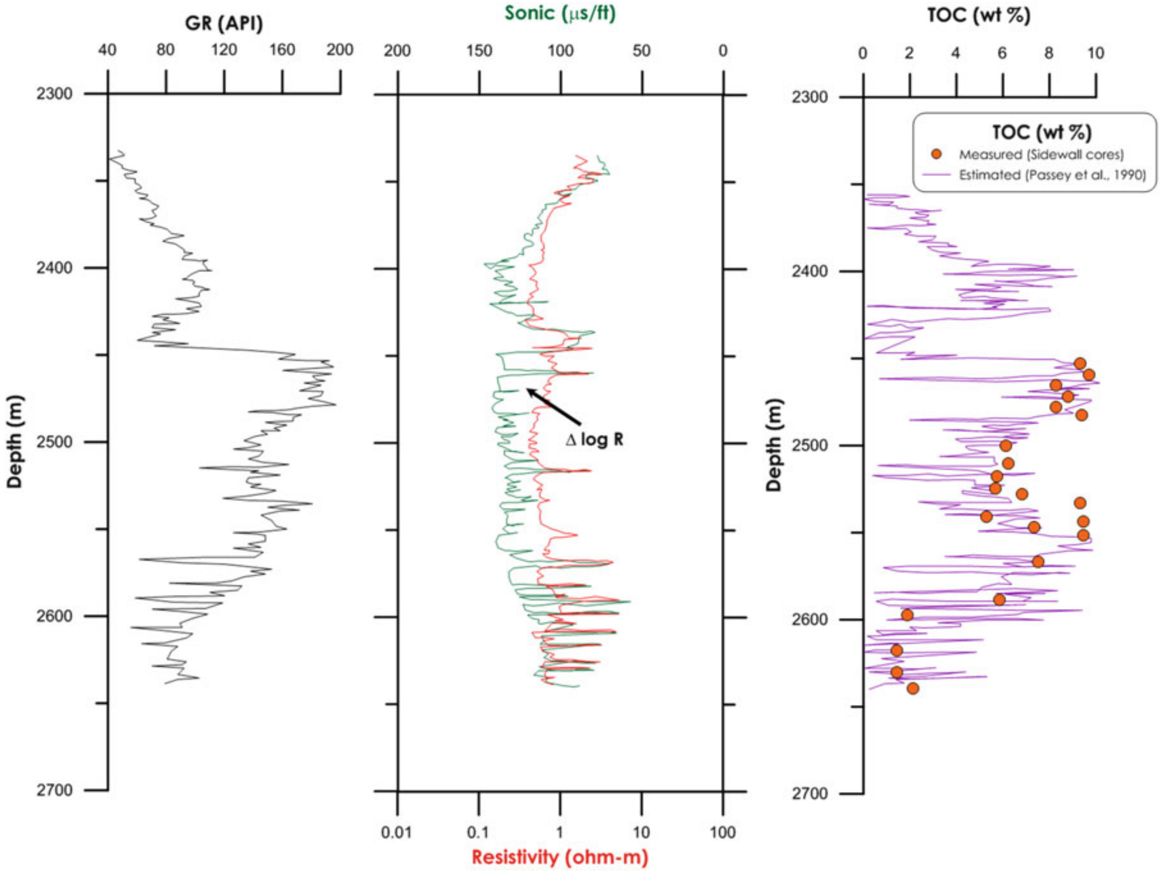

Fig. 16.33 Sonic/resistivity overlay showing ΔlogR separation in the organic-rich interval (zone of high gamma ray value). The estimated TOC (using Passey et al. 1990 ΔlogR method) compared to measured TOC plotted against depth. The measured TOC values are from sidewall cores

The sonic log is plotted on a normalised scale with the resistivity log. When the normalised scales are correct, the sonic and resistivity logs track one another, regardless of compaction and compositional changes, but separate when a source rock is present (Passey et al. 1990). The degree of separation is said to be related to both degree of maturity and magnitude of TOC%, so that if the level of maturity is known, the TOC% can be calculated using the following empirical relational:

$$\mathrm{TOC\%} = (\Delta\mathrm{logR}) \times 10^{(2.297-0.1688\times\mathrm{LOM})} \quad (16.18)$$

where TOC% is the total organic carbon in %, LOM is the level of maturity and ΔlogR is the curve separation in resistivity unit. This method seems to be useful qualitatively, but quantitatively is cumbersome and its validity is doubtful.

16.5.7.3 Uncertainties of Resistivity and Conductivity Logs

Temperature effects The resistivity of formation fluids and drilling muds varies greatly with temperature. The temperature in a borehole can be found directly from temperature logs up the entire borehole, or more traditionally, from the geothermal gradient. In the former case the temperature is given directly at a given depth. However, this is not used to calculate the mud resistivity.

Effects of drilling mud The resistivity is strongly influenced by the invasion of drilling mud into the flushed and invaded zones. At least three resistivity measurements, each sensitive to a different distance away from the borehole, are needed to measure a resistivity transitional profile. These three measured values represent the resistivity of flushed (R_{xo}), invaded (R_i)

and uninvaded zones (R_t) (Fig. 16.32). Note that the degree of underestimation or overestimation in R_t and R_w leads to significant error in saturation calculation.

Estimation of *m* and *n* In attempting to reduce errors in S_w calculation we must ensure that the m and n parameters in Archie's equation are measured using independent methods. Laboratory determined *m* and *n* values are the best ones to take, though early in a reservoir's life these are not available, and so guesses are used instead. Note that 20% underestimations and overestimations of *m* and *n* lead to an underestimation and overestimation of the water saturation by 0.11 and 0.12 respectively. These are huge errors when progressed through to the STOOIP (stock tank oil originally in place) calculation.

16.5.8 Dipmeter Logs

16.5.8.1 Generalities and Basic Principles

The dipmeter is essentially a multi-arm microresistivity logging tool that provides data used to compute formation dip. Three to eight spring-loaded arms record separate microresistivity tracks, while within the sonde, a magnetic compass records the orientation of the tool as it is drawn up the hole (Fig. 16.34). A software program is used to correlate deviations on the logs and calculate the amount and direction of bedding dip. As a result structural dip is determined. The common dipmeter tools are FMS (Formation MicroScanner Sonde), SHDT (Stratigraphic High-resolution Dipmeter Tool), HDT (High Resolution Dipmeter Tool) and OBDT (Oil-based Dipmeter Tool). As the dipmeter is brought up the hole, the electrodes on each arm are in contact with the rock layers. If the rock layer is dipping, different arms will contact the layers at different depths. The sequence of contacts between individual arms and each layer is used to compute the dip of the layer. If the layer is horizontal, all arms of the dipmeter contact the layer at the same level.

There are two common ways to present dipmeter data; stick and tadpole plots (Fig. 16.34). A *stick plot* uses lines (sticks) to show the dip measurements. Depth is recorded on the vertical axis. The angle on the stick is the dip measurement. In a *tadpole plot*, dip is plotted on the horizontal axis with zero dip on the left. Depth is in the vertical axis. Conventional dipmeter tadpole plots show the four common dip motifs, that is uniform (green) pattern, upward-decreasing (red) pattern, upward-increasing (blue) pattern and random (bag o'nails) pattern. Each motif can

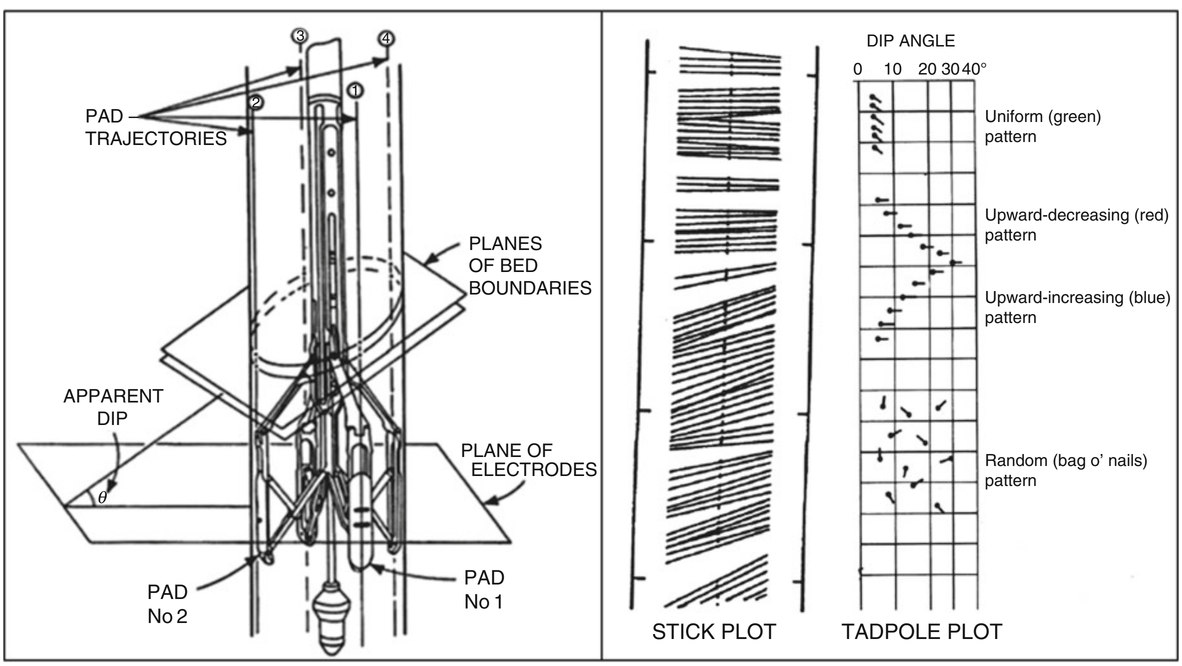

Fig. 16.34 Sketch of a four-arm dipmeter tool (HDT) with the trajectories the pads take when the tool is pulled uphole (modified from Hepp and Dumestre 1975). Also shown are two common ways (stick plot and tadpole plot) to present the dipmeter data

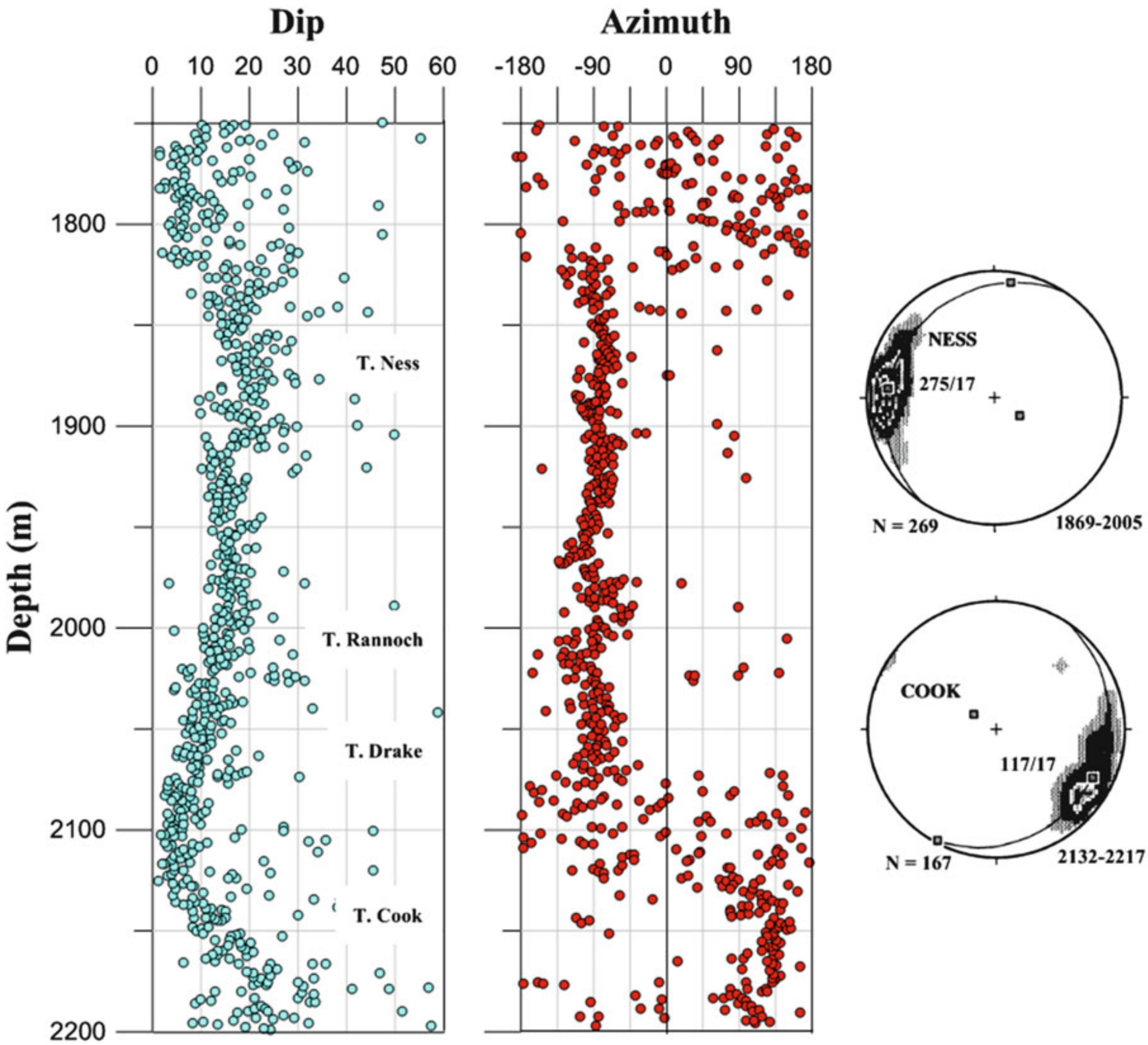

Fig. 16.35 The dip vs depth, and dip direction vs depth, plots from a well show an example of flattening drag towards a main fault. Bedding is dragged from westerly dip at shallower reservoir (Ness FM) to easterly dip at the base (Cook FM). The well does not penetrate the main fault, although several minor faults are encountered. (Modified from Hesthemmer and Fossen 1998)

be produced by several quite different geological phenomena. The position of the tadpole head shows the amount of dip and the tail shows the direction of dip.

16.5.8.2 Uses of Dipmeter Logs

Dipmeter data reflect dip and azimuth of bedding. Variations of these parameters down the boreholes help improve our understanding of the structural geology in faulted reservoirs (Fig. 16.35). The dipmeter data is used to evaluate magnitude and direction of structural and stratigraphic dips, improving the evaluation of thinly laminated sand/shale sequences, fracture detection, directional data to provide TVD, drift surveys and bottom hole location. Because the dipmeter measures the spatial orientation of physical properties in rocks, this method is also used to measure tectonic deformation of rocks, and not least the primary orientation of sediment particles (fabric). This is useful in beach sediments as the long axis of sand grains tends to be parallel with the shoreline, while in fluvial sandstones the sand grains will be oriented parallel with the transport direction. Dipmeter logs can therefore be very useful for reconstructing sedimentary environments, transport direction, etc.

16.5.8.3 Uncertainties of Dipmeter Logs

There are many uncertainties involved in interpreting dipmeter logs. The quality of the dipmeter data varies with the hole conditions, temperature and depth, type of mud used, rock type and tools. Generally FMS data are of better quality than SHDT data due to the increased button density and borehole coverage. Similarly, SHDT gives better results than HDT due to improvements of the tool and the algorithms used in processing. Data from the OBDT are generally of poorer quality than any of the resistivity tools (related to the use of oil-based mud), and results must accordingly be treated with care. Also it is not always possible to find dipmeter patterns that are compatible with sedimentological models of cross-bedded strata.

16.5.9 Image Logs

16.5.9.1 Generalities and Basic Principles

Borehole imaging has been one of the most rapidly advancing technologies in wireline well logging. The term "borehole imaging" refers to those logging and data-processing methods that are used to produce centimetre-scale images of the borehole wall and the rocks that make it up. The context is, therefore, that of open hole, but some of the tools are closely related to their cased-hole equivalents.

Borehole imaging can be performed by optical imaging, electrical imaging and acoustic imaging. A wide range of imaging tools is available, among them CBIL (Circumferential Borehole Imaging Log), UBI (Ultasonic Borehole Imaging) and CAST (Circumferential Acoustic Scanning Tool), with LWD imaging tools becoming increasingly important. Optical imaging tools were the first borehole imaging devices. Today they furnish a true high-resolution colour image of the wellbore. Video cameras may record the lamination and bedding and because they are oriented, palaeocurrent direction may be inferred. This method may also be very useful for recording fractures and large vuggy pores.

Electrical (microresistivity) imaging devices were developed as an advancement on dipmeter technology. Traditionally, they have required a conductive borehole fluid, but this requirement has since been obviated by oil-based mud imaging tools. In the microresistivity imaging tool, the pads and flaps contain an array of button electrodes at constant potential (Fig. 16.36). An applied voltage causes an alternating current to flow from each electrode into the formation and then to be received at a return electrode on the upper part of the tool. The microelectrodes respond to current density, which is related to localised formation resistivity. The tool, therefore, has a high-resolution capability in measuring variations from button to button.

Acoustic borehole-imaging devices are known as "borehole televiewers". They provide 100% coverage of the borehole wall. Modern acoustic borehole imaging tools contain a magnetometer to provide azimuthal information. The borehole televiewer operates with pulsed acoustic energy so that it can image the borehole wall in the presence of opaque drilling muds. Short bursts of acoustic energy are emitted by a rotating transducer in pulse-echo mode. These travel through the drilling mud and undergo partial reflection at the borehole wall. Reflected pulses are received by the transducer. The amplitudes of the reflected pulses form the basis of the acoustic image of the borehole wall. Data are usually presented as depth plots of enhanced images of amplitude and borehole radius (Fig. 16.36). To some extent, the acoustic and electrical images are complementary because the ultrasonic measurements are influenced more by rock properties, whereas the electrical measurements respond primarily to fluid properties.

16.5.9.2 Uses of Image Logs

Borehole image logs provide high-resolution directional data sets and are powerful tools in subsurface reservoir characterisation. They span the scale gap between core and seismic observations and although they do not replace cores, they provide key sedimentological and sub-seismic structural information, allowing quantification of subsurface fracture networks and providing inputs to geomechanical and petrophysical studies. The applications of image logs range from detailed reservoir description through reservoir performance to enhanced hydrocarbon recovery. Specific applications are fracture identification, analysis of small-scale sedimentological features, evaluation of net pay in thinly bedded formations, and the identification of *breakouts* (irregularities in the borehole wall that are aligned with the minimum horizontal stress and appear where stresses around the wellbore exceed the compressive strength of the rock). It is important to detect open fractures and also partly healed fractures which cannot be closed by increased

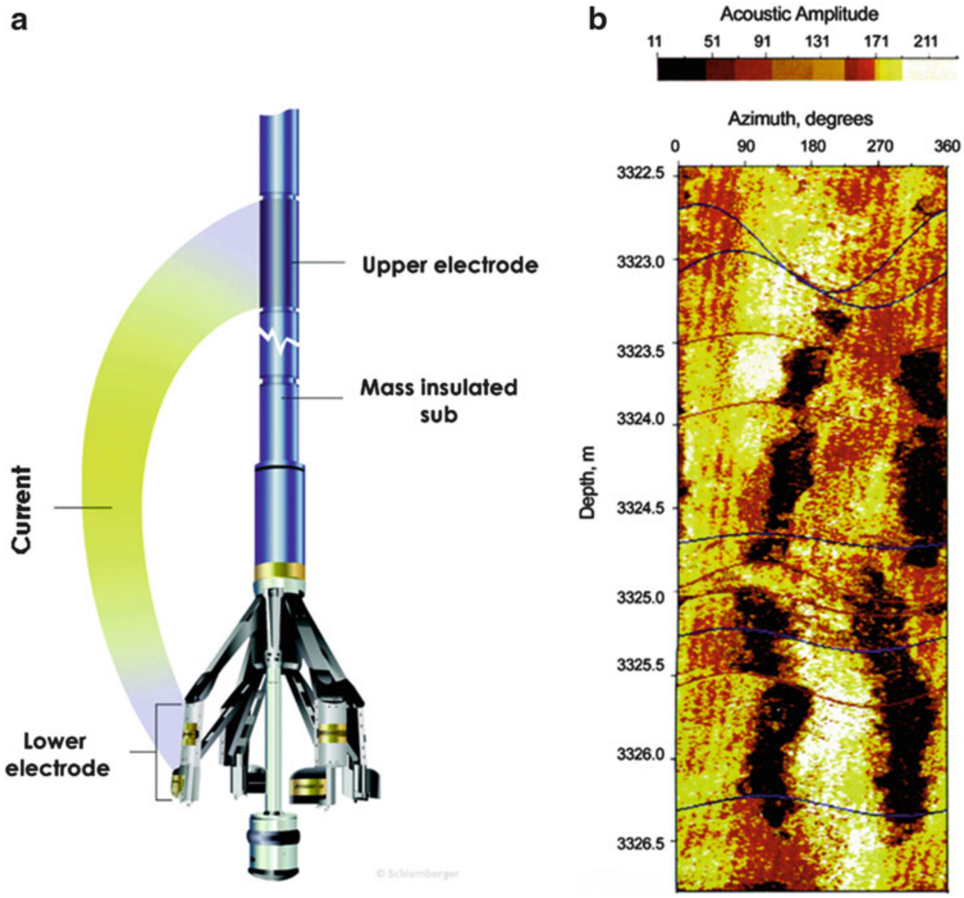

Fig. 16.36 (**a**) Measurement principle of electrical imaging (microresistivity imaging) devices illustrated by Schlumberger's Formation MicroImager (FMI) and (**b**) Example of breakout detection using an acoustic imaging borehole televiewer. Breakouts are indicated by the low acoustic amplitude of the reflected signal, shown here as *darker areas*. The breakouts are rotated because of a drilling-induced slippage of localised faults. (Courtesy of Schlumberger)

stress. Electrical images are similar to those obtained by dipmeter logs. Modern image logs provide a good overview of the lamination and also fractures. This may be compared with sedimentological logging of a core (Fig. 16.37).

16.5.9.3 Uncertainties of Image Logs

The principal drawback of optical imaging is that it requires a transparent fluid in the borehole. Unless transparent fluid can be injected ahead of the lens, the method fails. This requirement has limited the application of downhole cameras. The electrical imaging tool does not provide an absolute measurement of formation resistivity but rather a record of changes in resistivity. The resolution of electrical microimaging tools is governed by the size of the buttons, usually a fraction of an inch. In theory, any feature that is as large as the buttons will be resolved. If it is smaller, it might still be detected.

Acoustic imaging amplitudes are governed by several factors. The first is the shape of the borehole wall itself: irregularities cause the reflected energy to scatter so that a weaker reflected signal is received by the transducer. Examples of these irregularities are fractures, vugs and breakouts. Borehole televiewers work best where the borehole walls are smooth and the contrast in acoustic impedance is high. The scattering or absorption of acoustic energy by particles in the drilling mud can affect image resolution. This problem is more serious in heavily weighted muds, which are the most opaque acoustically and cause loss of image resolution.

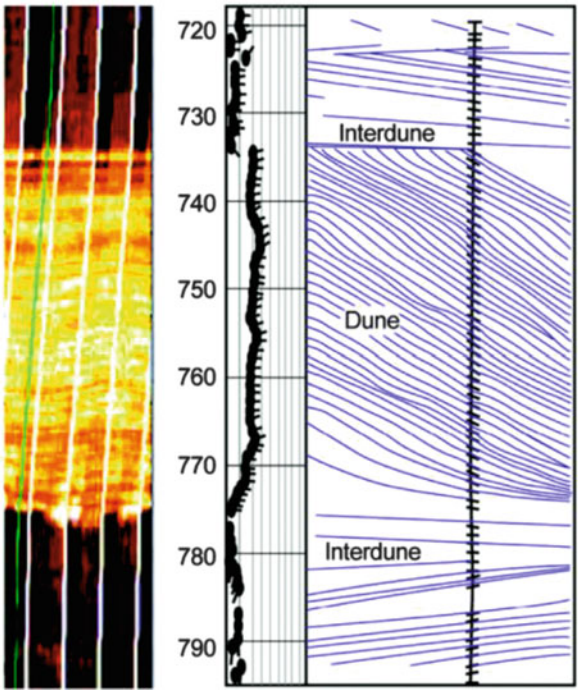

Fig. 16.37 Recognition of sedimentary and structural features in microresistivity images (*left*). These Formation MicroImager (FMI) images have been used to generate the dip information (*middle*). The combination of FMI images and dip data clearly differentiates the aeolian and interdune sands (*right*). (Courtesy of Schlumberger)

16.6 Summary

Well logs are the results of several geophysical measurements recorded in a well bore. Logging provides continuous recording of a physical parameter of the formation as a function of depth. The primary objectives of the well logging are (1) identification of source, reservoir and cap rocks, (2) determination of depth, thickness, temperature and pressure of the reservoir, (3) to distinguish between oil, gas and water zones in the reservoir, (4) estimation of hydrocarbon in place, and (5) estimation of recoverable hydrocarbon. Well logging is broadly classified into open-hole logging, cased-hole logging, MWD and LWD. In open-hole logging, the tool is lowered to the desired depth and data is acquired as the tool is pulled up. Logs are recorded to measure different physical parameters of a well to ascertain the capacity of the well to flow hydrocarbon. There are many physical parameters that can be recorded, depending upon requirements.

Well logging is the most abundant data acquisition technique available to help evaluate formation and determinate fluid saturation. Modern tools may record up to ten different types of measurement simultaneously during a single run. The most common measurements are radioactive, electric and acoustic logging. Rock properties are sensitive to changes in lithology and fluid content. Changes in rock properties are used to mark different formations. Well logs may be used both as a visual qualitative tool to identify the main rock types and also as a basis for sedimentological and stratigraphic interpretation.

In addition to providing information about the porosity and permeability of rock types, well logs can be used directly for interpreting depositional environments. Gamma logs and self-potential logs record characteristic coarsening-upward and fining-upward sequences very efficiently. We can therefore often recognise fluvial channels (fining-upward) and shallow marine deposits (coarsening-upward). Turbidities give a characteristic alternation between coarse and fine material. In delta sequences coal or lignite beds give characteristically strong deflections on the resistivity log. It is important, however, to bear in mind that the response of the logs is not due to sedimentological parameters such as grain size and sorting, but can be indirectly correlated with these parameters.

Physical measurements are related to rock properties such as lithology, porosity (fracture, vugs, primary and secondary), permeability, shaliness, and the type (oil, gas or condensate) and saturation of hydrocarbons. More quantitative calculations of porosity, shaliness and hydrocarbon saturation can also be made based on log data. Crossplots which are calibrated for different types of lithologies are then required. Correlation between wells can map units across a reservoir. Sonic and density logs provide a link between seismic and petrophysics.

In conclusion, when logging is properly applied, it can help to answer many questions from a wide spectrum of special interest groups on topics ranging from basic geology to petroleum economics. A single tool cannot perform a complete diagnosis of lithology and fluids. Usually a group of log measurements is made in the same hole to improve interpretation. Of equal importance, however, is the fact that logging by itself cannot provide answers to all questions. Coring, core analysis, and formation testing are also integral parts of any formation evaluation effort.

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