Chapter 4 - Measurement-While-Drilling (MWD), Logging-While-Drilling (LWD) and Geosteering

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Introduction

No other technology used in petroleum well construction has evolved more rapidly than measurement-while-drilling (MWD), logging-while-drilling (LWD), and geosteering. Early in the history of the oilfield, drillers and geologists often debated environmental and mechanical conditions at the drill bit. It was not until advances in electronic components, materials science, and battery technology made it technically feasible to make measurements at the bit and transmit them to the surface that the questions posed by pioneering drillers and geologists began to be answered.

The first measurements to be introduced commercially were directional, and almost all the applications took place in offshore, directionally drilled wells. It was easy to demonstrate the savings in rig time that could be achieved by substituting measurements taken while drilling and transmitted over the technology of the day. Single shots (downhole orientation taken by an instrument that measures azimuth or inclination at only one point) often took many hours of rig time since they were run to bottom on a slick line and then retrieved. As long as MWD achieved certain minimum reliability targets, it was less costly than single shots, and it gained popularity accordingly. Achieving those reliability targets in the harsh downhole environment is one of the dual challenges of MWD and LWD technology. The other challenge is to provide wireline-quality measurements.

In the early 1980s, simple qualitative measurements of formation parameters were introduced, often based upon methods proven by early wireline technology. Geologists and drilling staff used short, normal-resistivity and natural gamma ray measurements to select coring points and casing points. However, limitations in these measurements restricted them from replacing wireline for quantitative formation evaluation.

Late in the 1980s, the first rigorously quantitative measurements of formation parameters were made. Initially, the measurements were stored in tool memory, but soon the 2-MHz resistivity, neutron porosity, and gamma density measurements were transmitted to the
surface in real time. In parallel with qualitative measurements and telemetry, widespread use of MWD systems (combined with the development of steerable mud motors) made horizontal drilling more feasible and therefore, more common.

Soon, planning and steering horizontal wells on the basis of a geological model became inadequate. Even with known lithology of offset wells and well-defined seismic data, the geology of a directional well often varied so significantly over the horizontal interval that steering geometrically (by using directional measurements) was quickly observed to be inaccurate and ineffective. In response to these poor results from geometric steering, the first instrumented motors were designed and deployed in the early 1990s. Recent developments in MWD and LWD technology include sensors that measure the formation acoustic velocity and provide electrical images of dipping formations.

Before this discussion of MWD and LWD technology, it should be understood that the terms MWD and LWD are not used consistently throughout the industry. Within the context of this chapter, the term MWD refers to directional and drilling measurements. LWD refers to wireline-quality formation measurements made while drilling.

The purpose of this chapter is to describe the rationale behind the design of current MWD, LWD, and geosteering systems and to provide insight into the effective use of these systems at the wellsite.

**Measurement-While-Drilling (MWD)**

Although many measurements are taken while drilling, the term MWD is more commonly used to refer to measurements taken downhole with an electromechanical device located in the bottomhole assembly (BHA). Normally, the capability of sending the acquired information to the surface while drilling continues is included in the broad definition of MWD. Telemetry methods had difficulty in coping with the large volumes of downhole data, so the definition of MWD was again broadened to include data that was stored in tool memory and recovered when the tool was returned to the surface. All MWD systems typically have three major subcomponents of varying configurations: a power system, a directional sensor, and a telemetry system.
Power Systems

Power systems in MWD may be generally classified as two types: battery and turbine. Both types of power systems have inherent advantages and liabilities. In many MWD systems, a combination of these two types of power systems is used to provide power to the toolstring with or without drilling fluid flow or during intermittent drilling fluid flow conditions.

Batteries can provide tool power without drilling-fluid circulation, and they are necessary if logging will occur during tripping in or out of the hole.

Lithium-thionyl chloride batteries are commonly used in MWD systems because of their excellent combination of high-energy density and superior performance at LWD service temperatures. They provide a stable voltage source until very near the end of their service life, and they do not require complex electronics to condition the supply. These batteries, however, have limited instantaneous energy output, and they may be unsuitable for applications that require a high current drain. Although these batteries are safe at lower temperatures, if heated above 180°C, they can undergo a violent, accelerated reaction and explode with a significant force. As a result, there are restrictions on shipping lithium-thionyl chloride batteries in passenger aircraft. Even though these batteries are very efficient over their service life, they are not rechargeable, and their disposal is subject to strict environmental regulations.

The second source of abundant power generation, turbine power, uses what is available in the rig's drilling-fluid flow. A rotor is placed in the fluid stream, and circulating drilling fluid is directed onto the rotor blades by a stator. Rotational force is transmitted from the rotor to an alternator through a common shaft. The power generated by the alternator is not normally in an immediately usable form, since it is a three-phase alternating current of variable frequency. Electronic circuitry is required to rectify the alternating current (AC) to usable direct current (DC). Turbine rotors for this equipment
must accept a wide range of flow rates so that multiple sets of equipment will not be required to accommodate all possible mud pumping conditions. Similarly, rotors must be capable of tolerating considerable debris and lost-circulation material (LCM) entrained in the drilling fluid. Surface screens are often recommended to filter the incoming fluid.

Telemetry Systems

Although several different approaches have been taken to transmit data to the surface, mud-pulse telemetry is the standard method in commercial MWD and LWD systems. Acoustic systems that transmit up the drillpipe suffer an attenuation of approximately 150 dB per 1000 m in drilling fluid (Spinnler and Stone, 1978). Advances in coiled tubing promise new development opportunities for acoustic or electric-line telemetry. Several attempts have been made to construct special drillpipe with an integral hardwire. Although it offers exceptionally high data rates, the integral hardwire telemetry method requires expensive special drillpipe, special handling, and hundreds of electrical connections that must all remain reliable in harsh conditions.

Low-frequency electromagnetic transmission is in limited commercial use in MWD and LWD systems. It is sometimes used when air or foam are used as drilling fluid. The depth from which electromagnetic telemetry can be transmitted is limited by the conductivity and thickness of the overlying formations. Some authorities suggest that repeaters or signal boosters positioned in the drillstring extend the depth from which electromagnetic systems can reliably transmit.

Three mud-pulse telemetry systems are available: positive-pulse, negative-pulse, and continuous-wave systems. These systems are named for the way their pulse is propagated in the mud volume.
Negative-pulse systems create a pressure pulse lower than that of the mud volume by venting a small amount of high-pressure drillstring mud from the drillpipe to the annulus. Positive-pulse systems create a momentary flow restriction (higher pressure than the drilling mud volume) in the drillpipe. Continuous-wave systems create a carrier frequency that is transmitted through the mud and encode data using phase shifts of the carrier. Positive-pulse systems are more commonly used in current MWD and LWD systems. This may be because the generation of a significant-sized negative pulse requires a significant pressure drop across the BHA, which reduces the hole-cleaning capacity of the drilling fluid system. Drilling engineers can find this pressure drop difficult to deliver, particularly in the extended-reach wells for which the technology is best suited. Many different data coding systems are used, which are often designed to optimize the life and reliability of the pulser, since it must survive direct contact from the abrasive, high-pressure mud flow.

Telemetry signal detection is performed by one or more transducers located on the rig standpipe, and data is extracted from the signals by surface computer equipment housed either in a skid unit or on the drill floor. Real-time detection of data while drilling is crucial to the successful application of MWD in most circumstances. Successful data decoding is highly dependent on the signal-to-noise ratio.

A close correlation exists between the signal size and telemetry data rate; the higher the data rate, the smaller the pulse size becomes. Most modern systems have the ability to reprogram the tool’s telemetry parameters and slow down data transmission speed without tripping out of the hole; however, slowing data rate adversely affects log-data density.

The sources of noise in the drilling-fluid pressure trace are numerous. Most notable are the mud pumps, which often create a relatively high-frequency noise. Interference among pump frequencies leads to harmonics, but these
background noises can be filtered out using analog techniques. Pump speed sensors can be a very effective method of identifying and removing pump noise from the raw telemetry signal.

Lower-frequency noise in the mud volume is often generated by drilling motors. As the driller applies weight to the bit, standpipe pressure increases; as the weight is drilled off, standpipe pressure is reduced. The problem is exacerbated when a polycrystalline diamond-compact (PDC) bit is being used. Sometimes, the noise becomes so great that even at the lowest data rates, successful transmission can only occur when bit contact is halted and mud flow is circulated off-bottom. Well depth and mud type also affect the received signal amplitude and width. In general, oil-based muds (OBMs) and pseudo-oil-based muds (POBM) are more compressible than water-based muds; therefore they result in the greatest signal losses. This effect can be particularly severe in long-reach wells where OBM and POBM are commonly used for their improved lubricity. Nevertheless, signals have been retrieved without significant problems from depths of almost 9,144 m (30,000 ft) in compressible fluids.

**Directional Sensors**

The state of the art in directional sensor technology for several years has been an array of three orthogonal fluxgate magnetometers and three accelerometers. Although in normal circumstances, standard directional sensors provide acceptable surveys, any application where uncertainty in the bottomhole location exists can be troublesome.

Extended-reach wells, by nature of their measured depth, can suffer significant errors in bottomhole location. Geographical locations where the horizontal component of the earth's magnetic field is small affect directional sensor accuracy the most. Typical worst-case scenarios are seen when drilling east to west in the North Sea or Alaska. Sag in BHA components in high-angle or horizontal wells can also cause a systematic directional error.
Finally, diurnal variations in the earth's magnetic field, and local magnetic interference from BHA components can induce directional errors. Existing models for the prediction of errors in directional surveys were not designed for some of the extreme conditions encountered in today's drilling methods and well conditions.

Numerous methods of varying effectiveness are available to help correct raw magnetic readings for interference. Early corrections assumed that all interference was axial (along the drillstring's axis); more recent methods analyze for both permanent and induced interference on three axes. If magnetic readings can be corrected for variations in the diurnal field, even greater confidence can be placed in the accuracy of bottomhole location. Along with uncertainties in the measured depth, bottomhole location uncertainties are one contributor to errors in the absolute depth. Note that all methods of real-time azimuth correction require raw data to be transmitted to the surface, which imposes load on the telemetry channel.

Gyroscope (gyro)-navigated MWD offers significant benefits over existing navigation sensors. In addition to greater accuracy, gyros are not susceptible to interference from magnetic fields. Current problems with gyro technology center upon incorporating mechanical robustness, minimizing external diameter, and overcoming temperature sensitivity.

**MWD and LWD System Architecture**

As MWD and LWD systems have evolved, the importance of customized measurement solutions has increased. The ability to add and remove measurement sections of the logging assembly as wellsite needs change is valuable, thus prompting the design of modular MWD/LWD systems. Methods for such design and operational issues as fault tolerance, power sharing, data sharing across tool joints, and memory management have become increasingly important in LWD systems.
In most cases, a natural division in system architecture exists when tool (drilling collar) ODs are 4 3/4 in. or less. Smaller-diameter tool systems tend to use positive-pulse telemetry systems and battery power systems, and are encased in a probe-type pressure housing. The pressure housing and internal components are centered on rubber standoffs and mounted inside a drill collar. Some MWD/LWD systems, although located in the drill-collar ID, are retrievable and replaceable, in case tool failure or tool sticking occurs. Retrievability from the drill collar in the hole often compromises the system's mounting scheme and, therefore, these types of systems are typically less reliable. Since the MWD string can be changed without tripping the entire drillstring, retrievable systems can be less reliable but still be cost-effective solutions.

In tool ODs of 6 3/4 in. or more, LWD systems are often turbine-powered since larger collar ODs enable optimal mud flow. When used with other modules, interchangeable power systems and measurement modules must both supply power and transmit data across tool joints. Often, a central stinger assembly protrudes from the lower collar joint and mates with an upward-looking electrical connection as the collar-joint threads are made up on the drillfloor. These electrical and telemetry connections can be compromised by factors such as high build rates in the drillstring and electrically conductive muds. Recent MWD/LWD designs ensure that each module contains an independent battery and memory so that logging can continue even if central power and telemetry are interrupted. Stand-alone module battery power and memory also enable logging to be performed while tripping out of the hole.

**Drilling Dynamics**

The aim of drilling dynamics measurement is to make drilling the well more efficient and to prevent unscheduled events. Approximately 75% of all lost-time incidents over 6 hours are caused by drilling mechanics failures
(Burgess and Martin, 1995). Therefore, extensive effort is made to ensure that both the drilling mechanics information acquired is converted to a format usable by the driller, and that usable data are provided to the rig floor.

The downhole drilling mechanics parameters most frequently measured are weight on bit (WOB), torque on bit (TOB), shock, and temperature. Downhole pressures, ultrasonic caliper data, and turbine speed can also be acquired. The data that are provided by these measurements are intended to enable informed, timely decisions by the drilling staff and thereby improve drilling efficiency.

Stuck drillpipe is one of the major causes of lost time on the drilling rig. This condition is normally caused either by differential sticking of the drillstring to the borehole wall or by mechanical problems such as the drillstring becoming keyseated into the formation. Excessive friction applied to the string by a swelling formation can also cause downtime. Models have been developed that can calculate and predict an axial or torsional friction factor. These models are normalized to account for hole inclination and BHA configuration. A buildup in these friction factors usually suggests that preventive action (such as a wiper trip) is necessary. By directly comparing this information with the drilling history of adjacent offset wells, professionals can often determine whether problems are caused by formation characteristics or other mechanical factors such as bit dulling.

To have a positive effect on drilling efficiency, drilling dynamics must have a quick feedback loop to the drilling decision-makers on the rig site. An example of quick feedback loop benefits is found in the identification of bit bounce. As downhole processing power has increased, recent advances have made it possible to observe the cyclic oscillations in downhole weight-on-bit (Hutchinson et al., 1995). If the oscillations exceed a predetermined threshold, they can be diagnosed as bit bounce and a warning is transmitted
to the surface. The driller can then take corrective action (such as altering weight on the bit) and observe whether the bit has stopped bouncing on the next data transmission (Figure 4-1).

**Figure 4-1** Downhole sensors provide useful drilling measurements when combined with a user-friendly display

Other conditions, such as "stick-slip" (intermittent sticking of the bit and drillstring with rig torque applied, followed by damaging release or slip) and torsional shocks can also be diagnosed and corrected.

Another means of acquiring drilling dynamics data through the use of downhole shock sensors, has become increasingly popular in recent years. Typically, these sensors count the number of shocks that exceed a preset force threshold over a specific period. This number of occurrences is then transmitted to the surface. Downhole shock levels can be correlated with the
design specification of the MWD tool. If the tool is operated over design thresholds for a period, the likelihood of tool failure increases proportionally. A strong correlation, of course, exists between continuous shocking of the BHA and the mechanical failure that causes the drillstring to part. In most cases, lateral shock readings have been observed at significantly higher levels than axial (along the tool axis) shock, except when jarring the drillstring. Multiaxis accelerometers are available and enable a more detailed analysis of shock forces.

*Downhole pressure-measurement-while-drilling* is an often misunderstood concept. Conventional formation testers, which isolate a section of formation from the borehole, are not currently available in "while-drilling" form. Pressure-measurement-while-drilling has proved valuable in extended-reach wells where long tangent sections may have been drilled. Studies performed on such wells have shown that hole cleaning can be difficult and that cuttings can build up on the lower side of the borehole. If this buildup is not identified early enough, loss of ROP and sticking problems can result. A downhole annulus pressure measurement can monitor backpressure while circulating the mud volume and, assuming that flow rates are unchanged, it can precisely identify when a wiper trip should be performed to clean the hole. Pressure measurements can also help monitor and alter mud weight and optimize equivalent circulation density (ECD).

Historically, drilling dynamics measurements have not been commercially successful. Many rigsite staff choose to rely on experience gained rather than measurements made. A major reason for discounting the integrity of these systems is that the intelligence of the systems needs to be improved to prevent false alarms. The future of drilling dynamics measurements most probably lies with the MWD companies themselves as they demonstrate their product's effectiveness in integrated contracts.
Reliability and Environmental Factors

MWD systems are used in the harshest operating environments. Obvious conditions such as high pressure and temperature are all too familiar to engineers and designers. The wireline industry has a long history of successfully overcoming these conditions.

Most MWD tools can continue operating at tool temperatures up to 150°C. A limited selection of sensors is available with ratings up to 175°C. MWD tool temperatures may be 20°C lower than formation temperatures measured by wireline logs; this trend is caused by the cooling effect of mud circulation. The highest temperatures commonly encountered by MWD tools are those measured while running into a hole where the drilling fluid volume has not been circulated for an extended period. In cases such as this, it is advisable to break circulation periodically while running in the hole. Using a Dewar flask to protect sensors and electronics from high temperatures is common in wireline, where downhole exposure times are usually short. Using flasks for temperature protection is not practical in MWD because of the long exposure times at high temperatures that must be endured.

The development of a broader range of high-temperature sensors in MWD is not governed by technical issues but rather economic ones. Electronic component life above 150°C is significantly shortened, imposing high maintenance and repair costs of tools. System reliability in the 150°C to 175°C range can naturally be expected to suffer. Furthermore, battery-powered systems, such as Lithium alloy cells, have a lower energy density and hence shorter (but still adequate) life in this temperature range.

Downhole pressure is less a problem than temperature for MWD systems. Most toolstrings are designed to withstand up to 20,000 psi. The combination of hydrostatic pressure and system backpressure rarely approach this limit.
Shock and vibration present MWD systems their most severe challenges. Contrary to expectation, early tests using instrumented downhole systems showed that the magnitudes of lateral (side-to-side) shocks are dramatically greater than axial shocks during normal drilling. The exception to this rule is again when using jars on the drillstring. Modern MWD tools are generally designed to withstand shocks of approximately 500 G for 0.5 msec over a life of 100,000 cycles.

A more subtle, but no less destructive, force is caused by torsional shock. The mechanism that induces torsional shock, stick-slip, is caused by the tendency of certain bits in rare circumstances to dig into the formation and stop. The rotary table continues to wind up the drillstring until the torque in the string becomes great enough to free the bit. When the bit and drillstring break free, severe instantaneous torsional accelerations and forces are applied. If subjected to repeated stick-slip, tools can be expected to fail.

Many modern MWD devices are equipped with accelerometers that provide real-time measurements of the shock levels encountered and transmit these data to the surface. Drilling staff can then take remedial action to prevent either drillstring failure or MWD failure. No matter what preventive actions are taken however, some failures occur during drilling. A very high proportion of failures take place in the 5% of wells with the toughest environmental conditions. In these severe-condition wells, shock levels may exceed tool design specifications.

Early work done to standardize the measurement and reporting of MWD tool reliability statistics focused on defining a failure and dividing the aggregate number of successful circulating hours by the aggregate number of failures. This work resulted in a mean-time-between-failure (MTBF) number. If the data were accumulated over a statistically significant period, typically 2,000 hours, meaningful failure analysis trends could be derived. As downhole
tools became more complex, however, the IADC published recommendations on the acquisition and calculation of MTBF statistics (Ng, 1989).

A common misunderstanding exists between MTBF (which may be quoted as 250 hours for a triple combo system) and the service interval (which may be quoted as 200 hours). The service interval refers to the point at which the device might normally be expected to fail because of battery-life exhaustion or seal failure if it is not replaced by a serviced tool. The MTBF, as its name implies, is a mean. Statistically, no more probability of a failure exists in Hour 250 than in Hour 25, if the system has been properly serviced and is running within design specifications.

Drawing a parallel between automobiles and MWD systems, one commonly cited example illustrates the reliability challenge faced by MWD. For example, an automobile has an MTBF of 350 hours and it is being driven at 60 mph. On average, it will travel 21,000 miles before breaking down, roughly the circumference of the earth at the equator. To be considered economically viable, MWD tools are expected to perform the equivalent of these automotive service figures without the benefit of the maintenance or refueling that is an everyday requirement in automobile operation.

Logging While Drilling

Perhaps more than any other service, the use of LWD and geosteering technology demands teamwork. Successful operations can often be traced back to good planning and communications among geology, drilling, and contractor staffs. If drilling staff members manage the contract, they may choose a device that is not well suited to the replacement of wireline in a particular environment. If geology staff fail to communicate well with the drilling staff, then the tool may be run in the BHA at a point that renders the data unusable. Important issues that must be discussed cross-functionally
include the location of tools within the assembly, flow rates, mud types, and stabilization.

**Resistivity Logging**

The electromagnetic wave resistivity tool has become the standard of the LWD environment. The nature of the electromagnetic measurement requires that the tool be typically equipped with a loop antenna that fits around the OD of the drill collar and emits electromagnetic waves. The waves travel through the immediate wellbore environment and are detected by a pair of receivers. Two types of wave measurements are performed at the receivers. The attenuation of the wave amplitude as it arrives at the two receivers yields the attenuation ratio. The phase difference in the wave between the two receivers is measured, yielding the phase-difference measurement. Typically these measurements are then converted back to resistivity values through the use of a conversion derived from computer modeling or test-tank data.

The primary purpose of resistivity measurement systems is to obtain a value of true formation resistivity ($R_t$) and to quantify the depth of invasion of the drilling fluid filtrate into the formation. A critical parameter in MWD measurements is formation exposure time, the time difference between the drill bit disturbing in-situ conditions and sensors measuring the formation. MWD systems have the advantage of measuring $R_t$ after a relatively short formation exposure time, typically 30 to 300 minutes. Interpretation difficulties can sometimes be caused by variable formation exposure time, and logs should always contain at least one formation-exposure curve.

A knowledge of formation exposure time does not, however, rule out other effects. Figure 4-2 shows a comparison between phase and attenuation resistivity with an FET of less than 15 minutes and a wireline laterolog run several days later.
Figure 4-2 Comparison of EWR and wireline resistivity in a deeply invaded, high-permeability sandstone reservoir (EWR formation exposure time was 15 minutes compared with 3 days for the wireline laterolog.)

Even the attenuation resistivity has been dramatically affected by invasion, reading about 10 ohm-m, whereas the true resistivity is in the region of 200 ohm-m.

Another example, shown in Figure 4-3, illustrates invasion effects in the interval from 2995 to 3025 ft.
Very deep invasion by conductive muds in the reservoir has caused the 2-MHz tool to read less than 10 ohm-m in a 200-ohm-m zone. Between 3058 and 3070 ft, the deep invasion has caused the hydrocarbon-bearing zone to be almost completely obscured. Only by comparison with the overlying, deeply invaded zone from 2995 to 3025 ft was this productive interval identified.

Similarly, LWD data density is dependent upon ROP. Good-quality logs typically have graduations or "tick" marks in each track to give a quick-look indication of measurement swings with respect to depth.

**Figure 4-3** Effects of very deep invasion by conductive muds. The oil zone between 3058 and 3067 m was almost overlooked because its EWR resistivity response was masked by deep invasion.
Early resistivity systems emphasized the difference between the phase and attenuation curves and suggested that one curve was a "deep" (radius of investigation) curve and another a "medium" curve. Difficulties with this interpretation in practice (Shen, 1991) led to the development of a generation of tools that derive their differences in investigation depth from additional physical spacings. A model of the measurement proportions from different areas around the borehole is shown in Figure 4-4.

![Figure 4-4](image)

**Figure 4-4** Contribution of zones around the borehole to the total measurement for phase and attenuation resistivities

Note that the attenuation measurement often reads deeper into the formation but has less vertical resolution than the phase measurement. Figure 4-5 shows a "tornado" chart that can be used to evaluate the invasion of saline or fresh mud filtrates. Identification and presentation of invasion profiles, particularly in horizontal holes, can lead to a greater understanding of reservoir mechanisms.
Figure 4-5 'Tornado' chart for the evaluation of saline or freshwater filtrates

Many of the applications in which LWD logs have replaced wireline logs occur in high-angle wells. This trend leads to an emphasis in LWD on certain specialist-interpretation issues.

The depth of investigation of 2-MHz wave resistivity devices is dependent on the resistivity of the formation being investigated. Measurement response of a device (both phase and attenuation) with four different receiver spacings is shown in Figure 4-6.
The region measured by the 25-in. (R25P) is based on a 25-in. diameter of investigation in a formation known to have a resistivity of 1 ohm-m. The phase measurement looks deeper (away from the borehole) and loses vertical resolution as the charts progress to greater resistivities. In contrast, the amplitude ratio at first looks deeper than the phase measurement, and the expected penalty of poorer vertical resolution is paid. In the most resistive case, the attenuation measurement shows a 129-in. diameter of investigation.

Dielectric effects are responsible for some discrepancies between phase and attenuation resistivity measurements. In defining the transform from the raw measurement to the calculated resistivities, certain assumptions are made about the formation dielectric constant. Dielectric constants are believed to be from 1 to 10. In shales and shaly formations, however, this assumption about dielectric constant is false, and as a result, phase readings will read too low and attenuation readings will read too high. Errors are greatest in the most resistive formations.
Further discrepancies between phase and attenuation resistivity measurements may also be attributed to the effects of formation anisotropy. Anisotropy may also be responsible for the separation of measurements taken at different spacings or at different frequencies. Anisotropy effects are caused by differences in the resistance of formation when measured across bedding planes ($R_v$) or along bedding planes ($R_h$). An assumption is generally made that $R_h$ is independent of orientation. As borehole inclination increases, the angle between the borehole and formation dip typically increases. When this relative angle exceeds about 40°, resultant effects become significant. Anisotropy has the effect of increasing the observed resistivity over $R_h$. Effects are greater on the phase measurements than the attenuation measurements and greater on longer receiver spacings than short ones.

Wave resistivity tools are run in most instances where LWD systems are used, but toroidal resistivity measurements are desirable under some circumstances (Gianzero, 1985). Toroidal resistivity tools typically consist of a transmitter that is excited by an alternating current, which induces a current in the BHA. Two receivers are placed below the transmitter, and the amount of current measured exiting the tool to the formation between the receivers is the lateral (or ring) resistivity. The amount of current passing through the lower measuring point is the bit resistivity (Figure 4-7).
Figure 4-7 Ring and bit resistivity measurements showing good corroboration. Bit resistivity measurements have only recently become truly quantitative

Because of the large number of variables involved, bit resistivity measurements have been difficult to quantify although there are signs that this is changing.

In formations with high resistivities (greater than 50 ohm-m) or where thin-bed identification is important, measurements with a toroidal resistivity tool may be more appropriate than measurements with other tool types.

The log example in Figure 4-8 shows a case where 2-MHz measurements have saturated because of the high salinity of the mud.
If the drilling fluid is conductive or if conductive invasion is expected, then toroidal resistivity measurement is preferred. If early identification of a coring or casing point is crucial, then bit resistivity measurements give a good first look. In geosteering applications, toroidal bit resistivity measurements are an immediate indicator of a fault crossing.

The first formation images while drilling were acquired through the use of toroidal resistivity tools. When a small-button electrode is placed on the OD of a stabilizer, the current flowing through that electrode can be monitored. The current is proportional to the formation resistivity in the immediate proximity. Effective measurements are best taken in salty muds with resistive formations. Vertical resolution is 2 to 3 in. and azimuthal resolution is less than 1 in. (Rosthal et al., 1996). With the tool rotating at least 30 rpm, internal magnetometer readings are taken and resistivity values are scanned and stored appropriately. The tool memory capacity is adequate for 150 hours of operation. At the surface, tool memory is dumped and the data are related to the correct depth. Quality checks are made to ensure that poor micro-depth measurements are not affecting the reading.

Imaging while drilling can provide a picture of formation structure, nonconformities, large fractures, and other visible formation features. Azimuthal density devices may also be processed to provide dip information. Research into acquiring and transmitting stratigraphic azimuth and dip while drilling is in progress.

**Nuclear Logging**

Gamma ray measurements have been made while drilling since the late 1970s. These measurements are relatively inexpensive although they require a more sophisticated surface system than is needed for directional measurements. Log plotting requires a depth-tracking system and additional surface computer hardware.
Applications have been made in both reconnaissance mode, where qualitative readings are used to locate a casing or coring point, and evaluation mode. Verification of proper MWD gamma ray detector function is normally performed in the field with a thorium blanket or an annular calibrator (Brami, 1991).

The main differences between MWD and wireline gamma ray curves are caused by spectral biasing of the formation gamma rays and logging speeds (Coope, 1983).

Neutron porosity ($\Phi_n$) and bulk density ($\rho_b$) measurements in LWD tools are typically combined in one sub or measurement module, and they are generally run together. Reproducing wireline density accuracy has proven to be one of the most difficult challenges facing LWD tool designers. Tool geometry typically consists of a cesium gamma ray source located in the drill collar and two detectors, one at a short spacing from the source and one at a long spacing from the source. Gamma counts arriving at each of the detectors are measured. Count rates at the receivers depend upon the density of the media between them. Density measurements are severely affected by the presence of drilling mud between the detectors and the formation. If more than 1 in. of standoff exists, the tendency of the gamma rays to travel the (normally less dense) mud path and "short circuit" the formation measurement path becomes overwhelming. Solving the gamma ray short-circuit problem is accomplished by placing the gamma detectors behind a drilling stabilizer. With the detector mounted in the stabilizer, in gauge holes, the maximum mud thickness is 0.25 in. and the mean mud thickness is 0.125 in. Response of the tool is characterized for various standoffs in various mud weights, and various formations and corrections are applied.

Placing the gamma detector in the stabilizer does have some drawbacks. Detector placement can affect the directional tendency of the BHA. In
horizontal and high-angle wells, in which the density measurement is most frequently run, the stabilizer can sometimes hang up and prevent weight from being properly transferred to the bit. It is important to note that in enlarged boreholes, gamma detectors deployed in the drilling stabilizer do not accurately measure density.

Assuming an 8 1/2-in. bit and an 8 1/4-in. density sleeve are used and the tool is rotating slowly in the hole, the average standoff is 0.125 in. and the maximum standoff is 0.25 in. If, however, the borehole enlarges to 10 in., the average standoff increases to 0.92 in., and the maximum standoff increases to 1.75 in. In big-hole conditions, very large corrections are required to obtain an accurate density reading. An example of an erroneous gas effect using older-generation density neutron devices in an enlarged 9 7/6-in. hole is shown in Figure 4-9.
Two approaches have been developed to obtain accurate density measurements in enlarged boreholes: an azimuthal density method and a constant standoff method. Azimuthal density links the counts to an orientation of the borehole by taking regular readings from a magnetometer (Holenka et al., 1995). When this method is used, the wellbore (which is generally inclined) is divided into four quadrants: bottom, left, right, and top. Incoming gamma counts are placed into one of the four bins. From this, four quadrant densities and an average density are obtained. A coarse "image" of the borehole can be obtained when beds of varying density arrive in one quadrant before another. Azimuthal density can be run without stabilization, but it relies on the assumption that standoff is minimal in the bottom quadrant of the wellbore.

The other method of obtaining density in enlarged boreholes relies on constant measurement of standoff using a series of ultrasonic calipers (Moake et al., 1996). A standoff measurement is made at frequent intervals and a weighted average is calculated. High weight is given to gamma rays arriving at the detector when the standoff is low and low weight is given to those gamma rays that arrive when the standoff is high (Figure 4-10).
This method attempts to replicate the wireline technique of dragging a tool pad up the side of the borehole. The constant standoff method can also be applied to neutron porosity tools.

All density measurements suffer if the drillstring is sliding in a horizontal borehole with the gamma detectors pointing up (away from the bottom of the wellbore). To overcome this problem, orientation devices are often inserted in the toolstring. As the BHA is being made up, the offset between the density sleeve and the tool face is measured. Adjusting the location of the orientation device allows the density measurement to be set to the desired offset. While the drillstring is sliding to build angle, the density detectors can be oriented downward by setting the offset to 180°.

LWD porosity measurements use a source (typically americium beryllium) that emits neutrons into the formation. Neutrons arrive at the two detectors
(near and far) in proportion to the amount they are moderated and captured by the media between the source and detectors. The best natural capture medium is hydrogen, generally found in the water, oil, and gas in the pore spaces of the formation. The ratio of neutron counts arriving at the detectors is calculated and stored in memory or transmitted to the surface. A high near/far ratio implies a high concentration of hydrogen in the formation and hence high porosity.

Neutron measurements are susceptible to a large number of environmental effects. Unlike wireline or LWD density measurements, the neutron measurement has minimal protection from mud effects. Neutron source/detector arrays are often built into a section of the tool that has a slightly larger OD than the rest of the string. The effect of centering the tool has been shown (Allen et al., 1993) to have a dramatic influence on corrections required compared to wireline (Figure 4-11).
Figure 4-11 Effects of tool centering showing significant effects of corrections compared to wireline

Standoff between the tool and the formation requires corrections of about 5 to 7 porosity units (p.u.) per inch. Borehole diameter corrections can range from 1 to 7 p.u./in., depending on tool design. Neutron porosity measurements are also affected by mud salinity, hydrogen index, formation salinity, temperature, and pressure. However, these effects are generally much smaller, requiring corrections of about 0.5 to 2 p.u.

Statistical effects are quite significant to nuclear measurements. Uncertainties increase as ROP increases. LWD nuclear measurements can be performed either while drilling or while tripping. Logging-while-drilling rates vary because of ROP changes, but they are typically range from 15 to 200 ft/hr, whereas instantaneous logging rates can be significantly higher.
Tripping rates can range from 1500 to 3000 ft/hr. Typical wireline rates are about 1800 ft/hr and constant. Statistical uncertainty in LWD nuclear logging also varies with formation type. In general, log quality begins to suffer increased statistical uncertainties at logging rates above 100 ft/hr. This limits the value of logging while tripping to repeating formation intervals of particular interest.

**Acoustic Logging**

Ultrasonic caliper measurements while drilling have been introduced principally for improving neutron and density measurements. Caliper transducers consist of two or more piezoelectric crystal stacks placed in the wall of the drill collar. These transducers generate a high-frequency acoustic signal, which is reflected by a nearby surface, ideally, the borehole wall. The quality of the reflection is determined by the acoustic impedance mismatch between the original and reflected signal. Often, there are restrictions in the quality of the caliper measurement in wells with high drilling fluid weights. The ultrasonic caliper measurement’s sensitivity to gas has led some to suggest its use as a downhole gas influx detector (Orban et al., 1991). Compared to the wireline mechanical caliper, the ultrasonic caliper provides readings with much higher resolutions.

The major wireline measurement missing from the LWD suite until recently has been acoustic velocity. Acoustic data are important in many lithologies for correlation with seismic information. These data can also be a useful porosity indicator in certain areas. Shear-wave velocity can also be measured and can be used to calculate rock mechanical properties. Four main challenges in constructing an LWD acoustic tool are described as follows (Aron et al., 1994):

- Preventing the compressional wave from traveling down the drill collar and obscuring the formation arrival. Unlike wireline tools, the bodies of LWD tools must be rigid structural members that can withstand and transmit drilling forces down the BHA. Therefore, it is impractical to adopt the
wireline solution of cutting intricate patterns into the body of the tool to delay the arrival of the compressional wave. Isolator design is crucial and is still implemented to enable successful signal processing in a wide variety of formations, particularly the slower ones [those having a compressional delta time ($\Delta t_c$) slower than approximately 100 µsec].

- Mounting transmitters and receivers on the OD of the drill collar without compromising their reliability
- Eliminating the effect of drilling noise from the measurement
- Processing the data so that it can be synthesized into a single $\Delta t_c$ and so that this data point can be transmitted by mud-pulse. This is particularly challenging, given the large quantity of raw data that must be acquired and processed.

In its most basic form, an acoustic logging device consists of a transmitter with at least two receivers mounted several feet away. Additional receivers and transmitters enhance the measurement quality and reliability. The transmitters and receivers are piston-type piezoelectric stacks that operate in the 20-kHz range, far from drilling noise frequencies. Drilling noise has been shown to be concentrated in the lower frequencies (Figure 4-12).

![Figure 4-12 Drilling noise is concentrated in the lower frequencies](image)

*Figure 4-12 Drilling noise is concentrated in the lower frequencies*
A data acquisition cycle is performed as the transmitter fires and the waveforms are measured and stored. Arrival time is measured from the time the transmitter fires until the wave arrives at each receiver. From this acoustic velocity information, the tool's downhole data processing electronics, using digital signal processing techniques, calculates the formation slowness or $\Delta t_C$. This value is the reciprocal of velocity and is expressed in units of $\mu\text{sec}/\text{ft}$. Waveforms are also stored in tool memory for later processing at the surface when the memory is dumped.

A development of the basic configuration is the compensated measurement (Minear et al., 1995). In this transmitter/receiver array, an additional transmitter is mounted an equal distance on the other side of the receivers and a standoff transducer is added. The classical wireline advantages gained by compensating acoustic measurements are that the effects of sonde tilt and borehole washouts are virtually eliminated from the log. Even more significant in LWD than wireline is the fact that compensation provides redundancy in the measurement. An upper and a lower $\Delta t_C$ are calculated. These two $\Delta t_C$ values provide a good preliminary indication of the quality of the downhole processing. If these values are relatively equal, processing is more likely to be correct. Memory size is very important in LWD acoustic tools. Typically, LWD acoustic tools require 10 to 20 times the memory capacity of other LWD devices to accommodate waveform storage.

The log in Figure 4-13 shows an example of a log processed at the surface from waveforms stored downhole.
Figure 4-13 Comparison of wireline and LWD acoustic measurements showing that acoustical size minimizes washout problems.
Here, the $\Delta t_c$ values have been reprocessed from the stored waveforms. When compared with a wireline log, this log is clearly less affected by the washout below the shoe and in the shale at X235 MD. LWD acoustic devices, by nature of their size, fill a much larger portion of the borehole than wireline devices and are less susceptible to the effects of borehole washout. The standoff measurement added to LWD acoustic tools can provide a useful indication of borehole conditions.

Synthetic seismograms can be produced when acoustic and density data are combined, which yield valuable correlations with seismic information. In certain acoustic applications, the shear-wave component can be extracted from the waveform and can be used to compute rock mechanical properties.

**Depth Measurement**

Good, consistent estimates of the absolute depth of critical bed boundaries are important for geological models. A knowledge of the relative depth from the top of a reservoir to the oil/water contact is vital for reserve estimates. Nevertheless, of all the measurements made by wireline and LWD, depth is one of the most critical, yet it is the one most taken for granted. Depth discrepancies between LWD and wireline have plagued the industry.

LWD depth measurements have evolved from mudlogging methods. Depth readings are tied, on a daily basis, to the driller’s depth. Driller’s depths are based on measurements of the length of drillpipe going in the hole and are referenced to a device for measuring the height of the kelly or top drive with respect to a fixed point. These instantaneous measurements of depth are stored with respect to time for later merging with LWD downhole memory data. The final log is constructed from this depth merge.

On fixed installations, such as land rigs or jackup rigs, a number of well-documented sources exist that describe environmental error being introduced in the driller's depth method. Floating rigs can introduce
additional errors. One study suggested the following environmental errors would be introduced in a 3000 m well (Kirkman and Seim, 1989).

**Drillpipe Stretch: 5- to 6-m Increase**

The weight of the string itself causes the bit to be significantly deeper than it was measured on surface. An additional effect can be noted when the driller allows the weight on bit to be drilled off. In this case, the bit may drill up to 2 m of formation without any measurable increase in depth at the surface. All new data recovered will be logged at the same depth.

Conversely, applying weight to the bit can lead to an apparent depth increase of up to 2 m as the drillpipe "squats" inside the hole. Pipe-squatting effects can cause a boundary to be logged at one depth by a density sensor; then by the time the neutron porosity log is run over the same interval, additional weight may be applied to the bit, causing pipe squat to occur and the boundary bed to appear (erroneously) to have shifted downhole by 1 m.

**Thermal Expansion: 3- to 4-m Increase**

Thermal effects, over the length of a 3000-m wellbore at 100°C higher than the drillpipe was measured on the surface, can cause considerable axial expansion.

**Pressure Effects: 1- to 2-m Increase**

Circulating pressures exerted on the drillpipe can cause collective axial length increase.

**Ballooning: 2-m Decrease**

The collective outward radial forces exerted on the ID of the drillpipe cause an overall contraction along the drillstring longitudinal axis.
In addition to the actual environmental effects on the drillstring, depth measurement techniques themselves have inherent errors associated with them. The two principal methods each have drawbacks. The measuring-cable method (geolograph wire) can be affected by high winds pulling more of the cable from the drum than is necessary. A second method, which uses an encoding device on the shaft of the draw-works, induces error because it cannot compensate for the number of cable wraps on the drum. Outer wraps have more depth associated with a revolution of the drum than inner wraps.

Floating rigs have special problems associated with depth measurements. Errors are principally caused by rig heave and by tidal action. In LWD, these effects are sufficiently overcome by the placement of compensation transducers on the relatively fixed rucker line.

Wireline measurements are also significantly affected by depth errors, as shown by the amount of depth shifting required between logging runs, which are often performed only hours apart. Given the errors inherent to depth measurement, if wireline and LWD ever tagged a marker bed at the same depth, it would be sheer coincidence.

Environmentally corrected depth would be a relatively simple measure to implement in LWD. Although this measure would certainly reduce depth errors, it most probably would not eliminate them. The "cost" of corrected depth is an additional depth measurement that must be monitored. The industry has yet to indicate that this additional measurement is merited. Running a cased-hole gamma ray during completion operations is a practice adopted by many operators as a check against LWD depth errors and lost data zones.

Geosteering

Although horizontal wells were occasionally drilled before the advent of MWD, the early 1990s saw a dramatic increase in horizontal activity. This
drilling anomaly was a result of a combination of factors. Offshore, many of the structures installed during the late 1970s and early 1980s needed to tap fresh reserves to remain commercial. Previously bypassed formations began to look accessible and appealing with the introduction of horizontal completion techniques. The more widespread use of 3D seismic techniques identified multiple small targets that showed economic potential if produced with horizontal technology. Several authorities suggested that during the planning of a well, the question should not be, " Shall we drill a horizontal well?" but, "Why should we drill a vertical well?"

**Geosteering Tools**

Most early horizontal wells were drilled using MWD and steerable systems in the traditional way with measurement arrays located up to 80 ft behind the bit. Geologists created a prognosis and the well planner would provide a trigonometric well path. The directional driller would follow the planner's path and hope that it intersected the payzone. In thicker zones, trigonometric steering is still practiced successfully. However, in thinner zones (less than 15 ft thick) it was soon recognized that MWD geological measurements could help steer the wellbore to and through the payzone, thus maximizing well efficiency. *Efficiency* is defined as the percentage of the well path passing through the payzone divided by the well’s total horizontal length. Efficiency is closely related to productivity, and one study in the North Sea suggested that the effect of reducing a net horizontal hole from 2000 ft to 1000 ft was a 30% productivity loss (Peach and Kloss, 1994).

A good definition of geosteering is "the drilling of a horizontal or other deviated well, where decisions on well path adjustments are made based on real-time geological and reservoir data." Biostratigraphy and analysis of relative hydrocarbons in the drilling-mud gases can also be used effectively where ROPs are low. If the ROP is sufficiently low and the sensors are
located an excessive distance behind the bit, biostratigraphy and relative hydrocarbon data may arrive before real-time MWD.

To avoid the multiple difficulties of trying to steer the well from far behind the bit, instrumented motors were developed. These drilling motors have onboard sensors to measure resistivity, gamma, and inclination. The data are sent back to the main mud pulser by a telemetry link, and the data are then subsequently sent to the surface. Typical telemetry links currently used include a hardwire routed through the motor or electromagnetic transmission. Although acquiring data close to the bit is important, designers must be careful not to compromise either the predictability of the motor or its ability to change path. A BHA used for geosteering is shown in Figure 4-14.

**Figure 4-14 A typical geosteering bottomhole assembly**
Downhole adjustable stabilizers are often run in combination with extended-reach geosteering applications. The blade diameter of the adjustable stabilizer is addressable from the surface. Thus, inclination may be controlled without resorting to sliding the drill motor. Resultant lower friction gives the BHA the advantage of a greater reach.

Many geosteering authorities believe that the most important sensor in an instrumented motor is not a formation sensor, but the inclinometer. This belief in inclinometer importance is even more true now that data can be acquired and transmitted during rotation. Any deviation from the planned TVD can be instantly observed and corrected. Early deviation recognition reduces the tortuosity of the wellbore and enables extended reach. Having inclination data at the bit immediately confirms that the corrective action was successful. It has been suggested that every foot the sensor is back from the bit leads to 2 ft in the recovery distance (Kashikar and Lesso, 1996). Other significant factors that affect the recovery distance are angle of incidence, reaction time, correction curve rate, hold distance, changes in structure, and curve distance to recovery (Figure 4-15).
Figure 4-15 Factors affecting the re-entry of a payzone exited by mistake

The relative merits of the various formation measurements are application-dependent. All rely on a good contrast between different marker beds or fluids. In most wells, either gamma or resistivity can provide a good indication. The best type of resistivity measurement (toroidal or wave) may vary, although resistivity data should always be available at the bit. In some geologic areas, neutron porosity and density measurements are the primary steering tools.

Two different approaches are currently being taken to geosteer with resistivity. The first approach includes a shallow-reading measurement at the bit. The second integrates an electromagnetic wave reading into the motor, farther behind the bit.
The resistivity-at-bit method is an extension of the toroidal method described in Section 4-3.1. In water-based mud, the electrical current passes down the body of the mud motor and exits into the formation. In oil-based mud, current flow relies on direct contact with the formation, achieved through the bit teeth contacting the formation. When logging occurs with a toroidal tool in oil-based drilling fluid, an electromagnetic device is usually run farther up the hole for formation evaluation purposes. Often, difficulties arise in resolving differences between the two resistivity measurements. Toroidal measurements can detect an approaching conductive bed more readily than an approaching resistive boundary. A further refinement, applicable in water-based drilling fluids, is a small button electrode. The electrode is linked to the high side of the motor, and in water-based muds, and it indicates whether the approaching bed is above or below the motor.

The second approach to geosteering with resistivity involves repackaging a standard wave resistivity measurement around an extended joint in the middle of the drilling motor. Very deep measurements can be made by altering the frequency of the transmission (from 2 MHz to 400 kHz). As the wellbore approaches the boundary, the resistivity reading will begin to deviate from its previous value. In most cases, it is unlikely that a change of less than 20% will be significant. Although this method does sense approaching beds from farther away, the depth of investigation may be counterproductive in thinner reservoirs. The electrode is necessarily 15 ft back from the bit and will not detect faults as quickly as a true at-bit measurement (Figure 4-16).
**Figure 4-16** The advantages of having a deep measurement compared to a shallower measurement at the bit

Currently, no azimuthal measurements of wave resistivity are available. In practice, given the relatively high percentage of geosteered wells that are drilled with oil-based muds, azimuthal resistivity has a narrow application.

In the geosteering environment, measurement issues such as formation anisotropy, shoulder-bed effects, and polarization horns become concerns. These formation characteristics must be modeled for a variety of well trigonometries. These models are used later as an aid to real-time interpretation at the rigsite.

The response of gamma ray devices can be made azimuthal. Indeed, the off-center packaging of most instrumented motors dictates that the detectors will be more sensitive to an approaching bed on one side of the motor than
the other. This effect can be exploited by shielding the detector and linking it to magnetometers so that either up, down, or quadrant information can be obtained. Azimuthal gamma ray measurements are principally useful for indicating whether the drillstring has exited the top or the bottom of a bed.

**Geosteering Methods**

Cross-functional teamwork and planning are the keys to success in geosteering wells. Typical geosteering team participants include geoscientists, drilling staff, the geosteering coordinator, and the directional driller.

Given the input data, the responsibility of the geoscientist is to provide an expected geological structure for the well.

The geosteering coordinator constructs a series of contingency-forward models. These models predict the response of the formation sensors to a different well path throughout the payzone. Factors that affect the path include formation thickness, shoulder bed effects, and the size of polarization horns. Figure 4-17 shows an example of geosteering in which an offset induction-gamma ray log from a vertical well is used as input.
The expected geosteering response at a given depth is predicted and displayed in the horizontal plane above the planned well trajectory. Two thin beds, evident in the wireline log above the main payzone, appear thicker on the geosteered log because of the inclination of the well.

Time is a luxury that the geosteering team rarely has for making decisions. At a typical drilling rate of 30 ft/hr, the engineer receives an average of two datapoints per foot of hole drilled. Figure 4-18 shows the actual log transmitted, alongside the model.
All the information correlates until the upper sand is exited. At this point, a rapid decision must be made about how to steer the well. Azimuthal testing can help determine which direction to drill. This testing involves placing azimuthal sensors above, at, and below the point in the wellbore where the unexpected event occurred. After taking a series of azimuthal measurements, the geosteering team can use this information to take the best remedial action to correct the geological model with known data. In practice, azimuthal data must be acquired and transmitted carefully since there is a possibility of washing out the hole or creating an inadvertent sidetrack in the wellbore. The effective presentation of data to make the decision-making process more intuitive is one of the primary challenges facing geosteering development in the years to come.

**Uses of Log Data**
Log data, whether acquired by wireline or LWD technology, have a wide range of applications, the most common of which relate to evaluation of the properties of formations penetrated and the fluids they contain. Examples of these applications include

- Reservoir characterization (lithology, mineralogy, producibility)
- Identification of hydrocarbons
- Discrimination of reservoir fluid types (gas, liquid)
- Quantification of hydrocarbon volumes (porosity, saturation)
- Structural and stratigraphic studies
- Evaluation of source rock and seal

All of these applications (and many more) fulfill critical roles in the task of finding and producing oil and gas. This section summarizes key aspects of the application of log data to the characterization of reservoirs and the identification and quantification of the hydrocarbons they contain. Although many different wireline logging tools have been designed to answer these questions, the following discussion will deal only with those tools that are currently in common LWD use and those that form a basic logging suite: gamma ray, resistivity, density and neutron (Jackson and Heysse, 1994; Tait and Hamlin, 1996).

**Reservoir Characterization**

Perhaps the most fundamental of all issues addressed by log data is the discrimination of reservoir and nonreservoir rocks. In elastic rock sequences, this practice commonly entails using the gamma ray curve to separate sandstones (reservoir) from shales (nonreservoir). Shales contain high percentages of clays with associated radioactive potassium and thorium, giving rise to high gamma ray (GR) count rates. Sandstones, however, are commonly quartz-rich and result in relatively lower gamma ray counts (Figure 4-7). In certain environments, sandstones may contain high levels of other minerals, such as potassium, feldspar, and mica which, because of their associated radioactive potassium, result in high gamma ray count rates. These "hot" sandstones may be mistaken for shales and require
density and neutron logs to characterize correctly. (See Figure 4-7 between 3912 and 3919 m.)

Between these two end members is a continuum of shaly sandstones and siltstones that can contain abundant clay but can still contain hydrocarbons. In these reservoirs, it is imperative to quantify accurately the percentage of clay that occupies porespace, which reduces the porosity or storage capacity of the reservoir and dramatically reduces the permeability or flow capacity of the reservoir.

The percentage of clay in a sandstone is commonly referred to as the shale volume, \( V_{sh} \). In the absence of "hot" sandstones, shale volume may be calculated by using Equation 4-1:

\[
V_{sh} = \frac{GR - GR_{\text{min}}}{GR_{\text{max}} - GR_{\text{min}}} \quad (4-1)
\]

where \( GR \) is the gamma ray log measurement, \( GR_{\text{min}} \) is the gamma ray measurement in clean (no clay) sandstone, and \( GR_{\text{max}} \) is the gamma ray measurement in shale.

**Identification and Quantification of Hydrocarbons**

All fluids in sedimentary rocks occur within the void space between the mineral grains, or matrix. Before the absolute value of such fluids, whether water, oil, or gas can be quantified, this void space or porosity must first be quantified.

**Porosity**

The density neutron tool combination is the primary source of porosity information used in LWD logging today because of its versatility as a porosity, gas, and shale indicator when compared to the difficulty of making a sonic transit time measurement in the harsh drilling environment.
Before any quantitative work, it is imperative to check that the logs are measuring correctly. To ensure accuracy, the logging contractor must compute neutron porosity in units that are compatible with the formation lithology limestone or sandstone). The density log should then be scaled so that it overlies the neutron in a clean (no clay), water-saturated reservoir. Typical scales appear in Table 4-1.

Table 4-1 Typical Scales

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Limestone</th>
<th>Sandstone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neutron (p.u.)</td>
<td>45</td>
<td>-15</td>
</tr>
<tr>
<td></td>
<td>60</td>
<td>0</td>
</tr>
<tr>
<td>Density (gm/cm³)</td>
<td>1.95</td>
<td>2.95</td>
</tr>
<tr>
<td></td>
<td>1.65</td>
<td>2.65</td>
</tr>
</tbody>
</table>

Where the lithology is sandstone but the neutron has been calculated in limestone units, the simple expedient of plotting density on a scale of 1.82 to 2.82 gm/cm³ will achieve a similar overlay (Figure 4-7 between 3920 and 3933 m). When this technique was used (Figure 4-9), the apparent gas effect in the known water-saturated sandstone below 3400 m in Track 2 was immediately recognized as bad log data. Use of the original data resulted in an overcalculation of porosity by 6.7 p.u., or a 29% error in volume. After the density log was corrected, the expected response was observed (Track 3), and the calculated porosity was consistent with surrounding wells.

Once the quality of the logs has been checked, the porosity can be calculated. If calculated with the appropriate matrix, neutron porosity (\(\Phi_n\)) can be read directly off the log, although care should be taken to check which corrections have been made to this log.

Density porosity (\(\Phi_d\)) can be calculated from the following equation:

\[
\Phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (4-2)
\]

where \(\rho_{ma}\) is the matrix grain density (gm/cm³), \(\rho_b\) is the bulk density (gm/cm³), and \(\rho_f\) is the formation fluid density (gm/cm³).

Formation porosity is then estimated by averaging density and neutron porosities:
The porosity calculated is the total porosity ($\Phi_t$) available for fluid storage. In elastic rocks, total porosity can be broadly subdivided into macro- and micro-porosity.

Macro-porosity is commonly associated with the term "effective" porosity ($\Phi_e$), which has many definitions, all of which attempt to define the percentage of the total porosity that is available to the storage of moveable fluids; therefore, this pore volume is capable of storing producible hydrocarbons.

Micro-porosity, often termed "ineffective" porosity, is that percentage of the total porosity that is filled with immovable formation water, bound in place by a range of physical and chemical processes. This pore volume ($\Phi_{sh}$) is commonly associated with clay and other fine-grained particles; this volume is unavailable to hydrocarbon storage.

Effective porosity may be calculated using the following equation:

$$\Phi_e = \Phi_t - (V_{sh} \times \Phi_{sh})$$  (4-4)

Where $\Phi_t$ is the total porosity (fraction), $\Phi_e$ is the effective (macro-) porosity (fraction), $\Phi_{sh}$ is the shale (micro-) porosity (fraction), and $V_{sh}$ is the shale volume (fraction).

**Water Saturations**

In clean formations, (total) water saturation can be calculated using the Archie equation:

$$S_{wl}^m = \frac{R_w a}{R_i \Phi_t^m}$$  (4-5)
where $S_{wt}$ is the percentage of the porosity filled with water (fraction), $R_w$ is the formation water resistivity (ohm-m), $R_t$ is the true formation resistivity (invasion corrected, ohm-m), $a$ is the tortuosity (~1), $m$ is the cementation factor (~2), and $n$ is the saturation exponent (~2).

Equation 4-5 breaks down in formations of shaly or complex lithologies. To calculate total water saturation in these reservoirs, more complex equations such as dual water equations or the Waxman-Smits equation are required to account for excess conductivity related to clays or other conductive minerals (Dewan, 1903; Serra, 1984). Once total water saturation has been calculated in these formations, it is commonly divided into effective and ineffective water saturation, on the assumption that hydrocarbon can be reservoired only in effective (macro-)porosity, whereas water occurs in both (Figure 4-19).

This saturation can be calculated by using the equation

$$
\phi_e (1 - S_{we}) = \phi_l (1 - S_{wt}) \quad (4-6)
$$

**Figure 4-19** Hydrocarbon saturation in complex lithologies is assumed to occur only in the effective porosity first
which can be rewritten as

\[
S_{we} = 1 - \left(1 - S_{wt}\right) \frac{\phi_t}{\phi_e} \tag{4-7}
\]

where \( \phi_t \) is the total porosity (fraction), \( \phi_e \) is the effective (macro-) porosity (fraction), \( S_{wt} \) is water saturation in total porosity (fraction), and \( S_{we} \) is water saturation in effective porosity (fraction).

**Formation Evaluation with LWD Instead of Wireline**

Intensive efforts have been made by LWD contractors to design and manufacture reliable tools that will provide measurements that are representative of formation properties. In addition, operators have gone to great expense running LWD/wireline comparisons to ensure consistency of these measurements. Despite these efforts, differences still remain because of the differing formation exposure times and logging environment confronted by LWD and wireline tools, and the differing technologies that have been used. In addition, the industry is now using LWD to drill and log high-angle, extended-reach wells never before contemplated with wireline technology.

The following is a summary of the observed differences between LWD and wireline data that could lead to errors in quantifying formation properties.

**Depth Control**

As discussed in Section 4-3.4, a difference of 5 to 10 ft between LWD and wireline depth systems is common and may take the form of incremental stretch or squeeze or the loss or gain of entire sections of data. Before any quantitative work being attempted, it is essential that all logs be exactly on depth. Therefore, a cased-hole gamma ray log should be run immediately after the casing so that any significant depth discrepancies can be identified. These depth discrepancies will affect each detector at different depths.
because of their different locations on the BHA relative to the GR which is used for checking with the cased-hole GR.

A further complication to LWD depth control arises when mixing circumferential and azimuthal measurements in the formation at high apparent dip to the wellbore. This complication occurs when water saturation is calculated with a circumferential EWR resistivity measurement and azimuthal, down-quadrant, density-neutron data. The azimuthal tools will "see" bed boundaries sooner (and sharper) than the circumferential tool that averages the resistivity measurement from both above and below the bed boundary (Figure 4.20).
Figure 4-20 Azimuthal tools run in highly deviated wells suffer depth shift, which must be corrected before quantitative analysis

This effect becomes progressively worse at higher apparent dips; as the wellbore becomes horizontal, the data may become unusable for quantitative analysis.

Gamma Ray

Gamma ray repeatability is a function of count rates that are related to detector volume and logging speed. The statistical repeatability of the LWD GR measurement is similar to that of the wireline tool, since the much lower count rates of LWD GR detectors (because of their reduced size) are largely compensated for by the much slower logging speed.

LWD GR detectors are more sensitive to gamma rays from potassium since the drill collars attenuate uranium and thorium gamma rays more than potassium gamma rays. While this effect, called spectral biasing, is generally less than 25%, it is most pronounced in shales and potassium-rich intervals. Although this effect is likely to be small when GR is used quantitatively, it may result in errors in calculated volumes of clay or potassium feldspar, which will affect porosity and saturation calculations.

Other sources of apparent difference between the wireline and LWD GR measurements are borehole effects. The hole diameter is commonly different between LWD and wireline logging, and corrections are made to different standard conditions.

Resistivity Logs

The resistivity measurement is affected by a complex array of physical properties of the formation, the wellbore, and the measurement system as discussed in Section 4-3.1. It is often difficult to resolve which effect is causing observed differences between LWD and wireline measurements can
often be difficult, since all effects may be contributing to differing degrees. In these situations, resistivity may have to be computer-modeled to quantify and correct for these effects.

**Frequency**

Resistivity is sensitive to the frequency at which it is measured. Because wireline tools operate at lower frequencies than LWD EWR devices, they tend to measure higher resistivity. Apparent formation water resistivity calculated from the LWD resistivity log is often inconsistent with that from wireline logs. At these higher operating frequencies (2 MHz), LWD tools are also more affected by dielectric effects than wireline tools. Above 20 ohm-m, dielectric properties become significant.

**Anisotropy**

Archie's equation (Equation 4-5) requires that resistivity be measured parallel to the formation bedding ($R_h$). At dips as low as $45^\circ$, LWD resistivities can read 10 to 20% higher than $R_h$ in shales and other anisotropic formations. Quantitative formation evaluation with LWD resistivity at relative dips greater than $60^\circ$ will certainly require anisotropy correction. This effect is much smaller on wireline than LWD because of the lower operating frequency, and it can often be ignored.

**Invasion**

LWD data are commonly acquired within 1 to 4 hours of drilling, whereas wireline logging commonly occurs 1 to 4 days after drilling. Although LWD resistivity tools are relatively shallow reading devices, the shallower depth of invasion at the time of LWD logging usually enables these devices to measure true formation resistivities. However, examples in high-permeability reservoirs as illustrated in Figure 4-2 and 4-3 demonstrate that this is not always true, and the logs must be carefully scrutinized to ensure
that no hydrocarbon zones have been overlooked. Figure 4-3 is an excellent example of this problem. The lower, deeply invaded zone (3060 m) was identified after careful comparison with the overlying known oil zone. An updip well was drilled to target bypassed oil trapped between the thin seals and discovered several million barrels that would not have been produced by existing wells. Invasion correction charts are only now becoming available to address this issue.

Density-Neutron

Standoff

Standoff is a common area of discrepancy between LWD and wireline porosity data. Standoff is commonly estimated from bit size, ultrasonic caliper, or a caliper derived from near and far detector count rates. In deviated wells where a change in wellbore trajectory may require sliding rather than rotating, detectors may be facing away from the formation, and standoff corrections may be incorrectly applied. All density-neutron logs should have the zones of sliding and rotating drillstring clearly marked and the method of standoff correction should be annotated.

Clay Hydration

Extended periods of exposure to water-based drilling fluid systems before wireline logging can cause shale hydration. Clays within the shales absorb water; depending on their mineralogy, they can swell between 2 and 50 times their original volume. This phenomenon causes wireline tools to record lower formation densities in shales than the densities recorded by LWD tools.

If hydration continues, it can cause sloughing and borehole stability problems. Washouts and hole rugosity can then severely degrade wireline porosity data, especially density data, which relies on pad contact with the borehole wall.
Invasion

Invasion also affects the gas effect shown on density-neutron logs, and it may either enhance or reduce that effect depending on the depth of invasion at the time of logging and the relative depth of investigation of the particular tools.

References


