8

SONIC OR ACOUSTIC LOGS

8.1 Generalities

The log

The sonic log provides a formation's *interval transit time*, designated Δt (delta-t, the reciprocal of the *velocity*). It is a measure of the formation's capacity to transmit sound waves. Geologically this capacity varies with lithology and rock texture, notably porosity (Figure 8.1).

(The main text of this chapter on the sonic logs concerns the conventional, general purpose sonic tools that only measure **compressional** *or* **P waves**, *the first arrival. A modern generation of tools is now able to measure the full wave train which includes the compressional wave, shear wave and Stoneley wave. These tools have more specialist applications and are considered in section* **8.8 Full waveform acoustic logs***).*

Principal uses

Quantitatively, the sonic log is used to evaluate porosity in liquid-filled holes. As an aid to seismic interpretation it can be used to give interval velocities and velocity profiles, and can be calibrated with the seismic section. Cross-multiplied with the density, the sonic is used to produce the acoustic impedance log, the first step in making a synthetic seismic trace.

Qualitatively, for the geologist, the sonic log is sensitive to subtle textural variations (of which porosity is only one) in both sands and shales. It can help to identify lithology and may help to indicate source rocks, normal

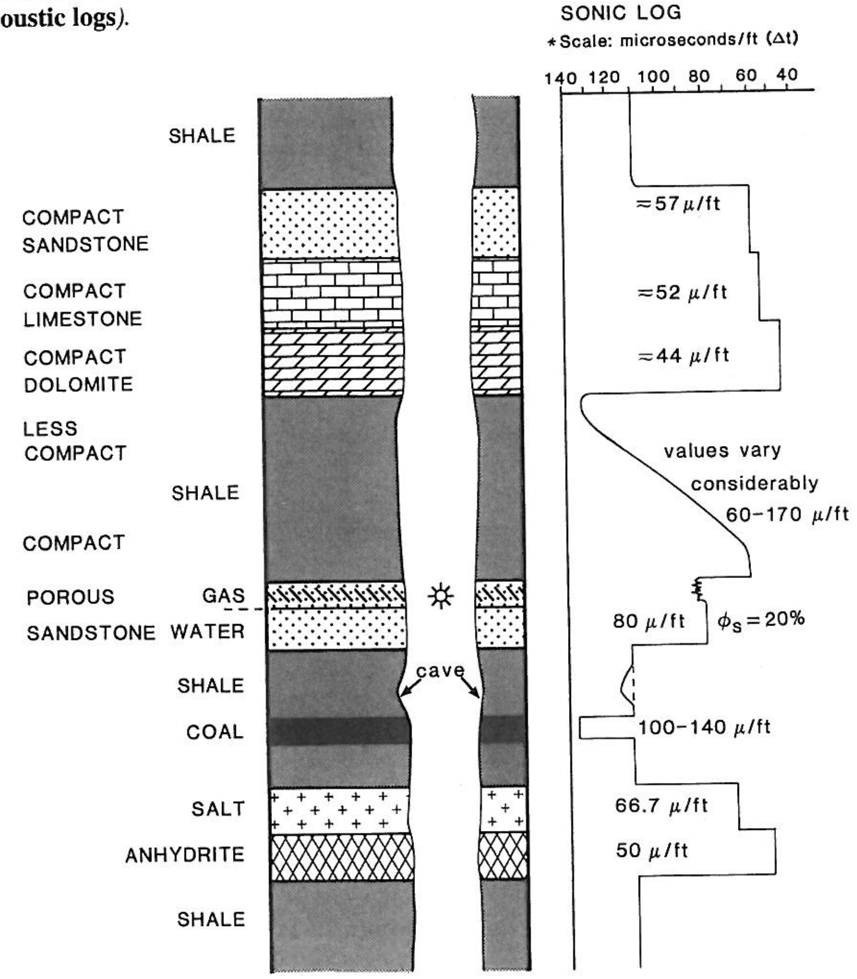


Figure 8.1 The sonic log: some typical responses. The sonic log shows a formation's ability to transmit sound waves. It is expressed as Interval Transit Time, Δt. *$(1 \times 10^6) / \Delta t$ = sonic velocity, ft/sec.

Table 8.1 The principal uses of the sonic log (conventional, compressional wave tools).

	Discipline	Used for	Knowing
Quantitative	Petrophysics	Porosity	Matrix velocity Fluid velocity
	Seismic	Interval velocity	Integrated travel time Seismic markers
		Seismic calibration	Check shots
		Acoustic impedance	Direct use of sonic log
Qualitative and semi-quantitative	Geology	Lithology	Matrix and mineral velocities
		Correlation	
		Texture	
		Fracture identification	Density log porosities
		Compaction and overpressure	Normal compaction trends
	Geochemistry	Source rock evaluation	Resistivity log values

compaction and overpressure and to some extent fractures. It is frequently used in correlation (Table 8.1).

8.2 Principles of measurement

The conventional, general purpose sonic tools measure the time it takes for a sound pulse to travel between a transmitter and a receiver, mounted a set distance away along the logging tool. The pulse measured is that of the compressional or ‘P’ wave (Figure 8.2) and tool design enables the velocity of this wave in the formation to be measured. The compressional wave is simply the fastest or ‘first arrival’, in which particles vibrate in the direction of the sense of movement. The compressional wave is followed by shear and Stoneley waves (Figure 8.2) which, in the conventional tools, are ignored but in the modern array acoustic tools, can be fully measured (Section 8.8).

Typical sonic tool transmitters (transducers) are either magnetostrictive or, more commonly, piezoelectric and translate an electrical signal into an ultrasonic vibration. Receivers are usually piezoelectric, and convert pressure waves into electromagnetic signals which can be amplified to provide the logging signal. Piezoelectric materials have a type of structure which, when a stress is applied, shows separation of centres of negative and positive charge, thus creating a polarisation charge. It is this, amplified, which gives an electrical signal. In piezoelectric transmitters, the application of an electrical charge causes a change in volume which can be translated into a pressure pulse. A common piezoelectric material used is lead zirconate titanate or PZT.

A sonic tool transmitter typically produces source frequencies of between 10–40kHz (kilohertz) or 10,000–40,000 cycles per second. At 10–20kHz, the acoustic wave has a wavelength of between 7.5cm (0.25ft) – 75cm (2.5ft) over the velocity range of 1500m/s (5000ft/sec) to 7500m/s (25,000ft/sec). This is clearly a huge contrast to the typical seismic signal (sonic and seismic velocities are routinely compared) which has a content in the 10–50 hertz range (i.e. 10–50 cycles per second) and with wavelengths of 30m–50m (*see* Section 8.7, Seismic applications).

8.3 Tools

Modern sonic tools do not consist of just a single emitter and a single receiver, but of a number of both transmitters and receivers, the actual arrangement depending on the tool type. Modern designs allow unwanted borehole and tool effects to be largely eliminated and give a reliable measure of formation values even in quite poor borehole conditions. Typical tool design and use of compensation can be illustrated by the borehole-compensated (BHC) sonic tool (Figure 8.4).

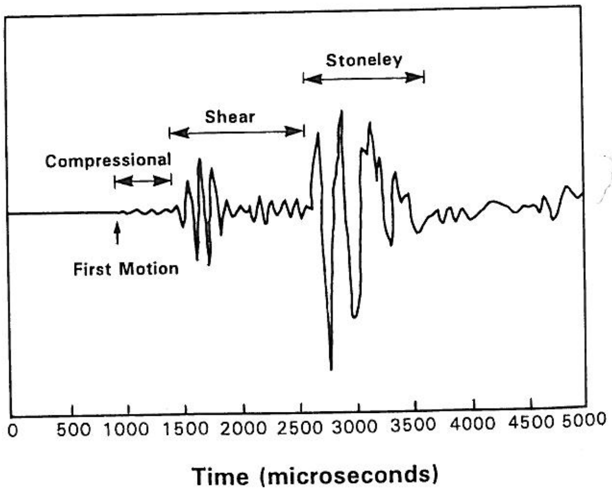


Figure 8.2 The full acoustic waveform that may be recorded in a borehole. The standard sonic records only the first arrival of the compressional (P) wave. Array sonic tools record the full waveform (modified from Ellis, 1987, after Schlumberger).

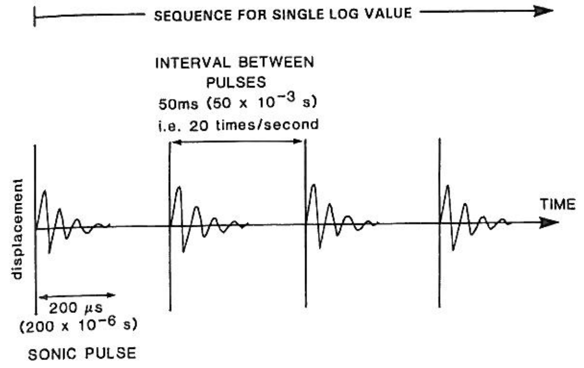


Figure 8.3 Sonic tool emitter patterns (schematic). Typically a pulse lasting 200 microseconds is emitted every 50 milliseconds, i.e. 20 times a second. Four pulses are needed for a complete (BHC) log measurement. (Re-drawn from Serra, 1979).

The borehole-compensated sonic tool has two transmitter-receiver groups (one inverted), each group consisting of a transmitter coupled with a near receiver and a far receiver (Figure 8.4*a*). Because the sonic is generally run hole-centred, any pulse transmitted by the tool, passes first into the mud, it is then refracted at the borehole wall, travels through the formation close to the borehole wall and, at a critical (slower) velocity is refracted back into the mud, so to reach the tool again where it is detected. A significant part of the trajectory is in the borehole mud (Figure 8.4*a*). However, if this travel path is considered when one transmitter is used with two receivers (a near and a far), the mud effects can be eliminated. This is simply achieved by measuring the time it takes for the signal to reach the far receiver and from this subtracting the time it takes to reach the near receiver. The path from tool to borehole wall and back, in the mud, is effectively common to both trajectories, as is the section of the path between the transmitter and near receiver: all are eliminated on subtraction. What is not common to the two trajectories is the time taken between

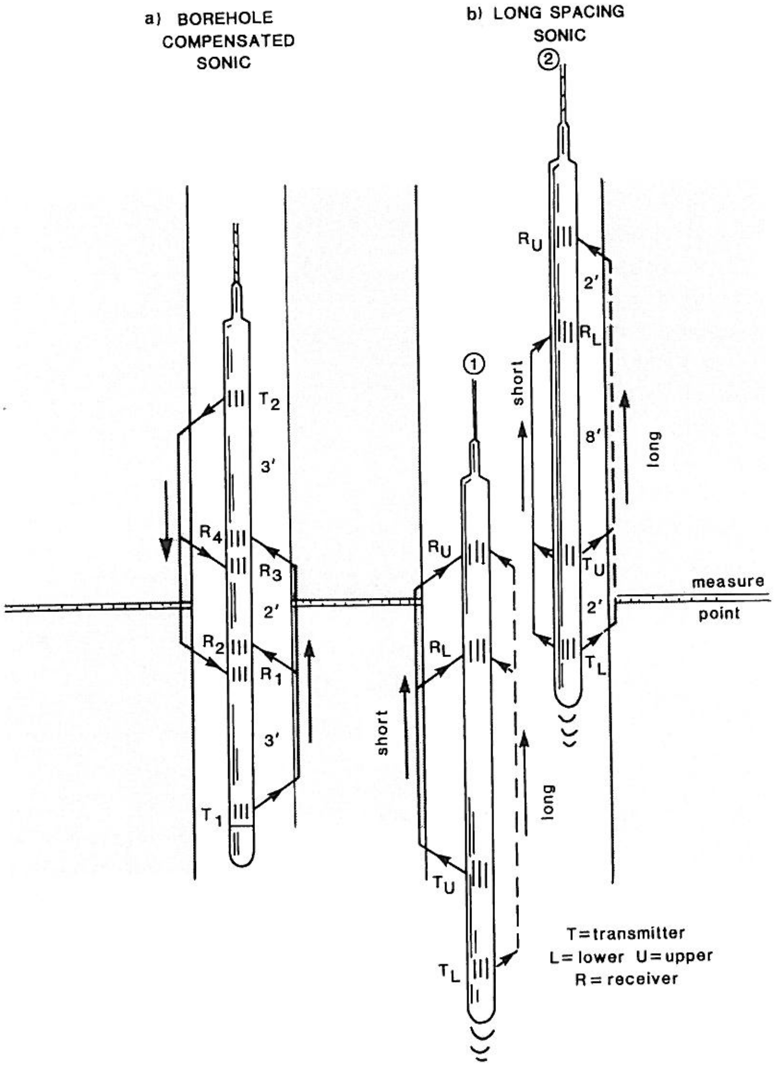


Figure 8.4 Sonic tools. Representations of (*a*) a borehole-compensated sonic tool which gives instantaneous readings with an inverted receiver transmitter array and (*b*) the Long Spacing Sonic Tool (Schlumberger) which gives long and short-spaced readings using a time (i.e. position) delay system: positions (1) and (2) are both relative to the same measure point. (Modified from Thomas, 1977 and Purdy, 1982).

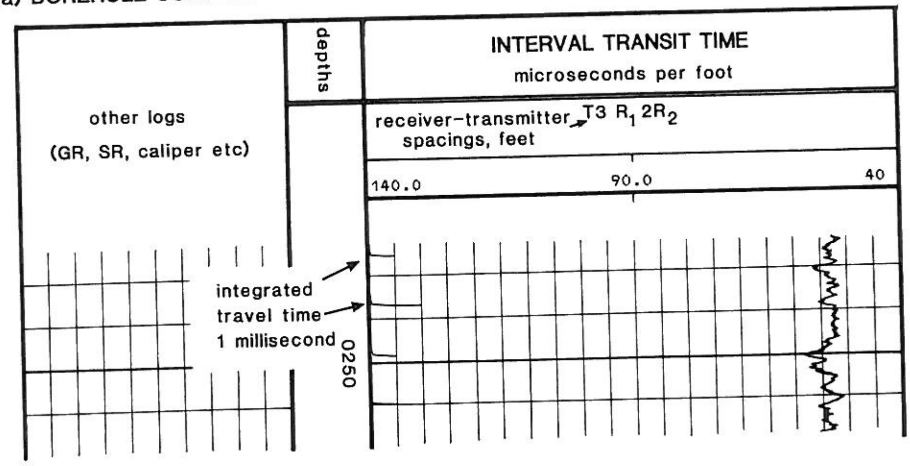
the two receivers (Figure 8.4*a*), and this time is the formation reading; the value required.

Since tool tilt and hole size may make the common parts of the trajectory unequal, a second, inverted array (with a downward moving signal), is averaged with the first (with the upward moving signal) to provide compensation. This means that each value recorded on the sonic log is the result of a sequence of four separate transmitter-receiver readings, two from the lower transmitter to its near and far receivers and two from the upper transmitter to its near and far receivers. The up and down receiver sets are offset vertically to allow for the tool moving (Figure 8.4*a*).

In terms of typical values for the BHC tool, a transmitter pulse lasts between 100μs – 200μs (microseconds), the gap between the pulses is 50ms (milliseconds) or 20 pulses per second, allowing five complete sequences of four individual transmitter-receiver readings per second (Figure 8.3). At a typical sonic tool logging speed of 1500m/h (5000ft/h), (i.e. approximately 40cm/sec or 16"/sec) each complete sequence of four readings will give one log reading for every 8cm (3") of borehole.

The borehole-compensated (BHC) sonic described above has a 'static' compensation and has been used commonly since the 1960s. It typically has transmitter-receiver distances of three feet and five feet with two feet between the two receivers (Figure 8.4*a*). In the late 1970s it was found that longer transmitter-receiver distances could help under certain borehole conditions and the long spaced sonic was designed with two receivers two feet apart separated by eight feet from two transmitters also two feet apart (i.e. the LSS of Schlumberger, Figure 8.4*b*, Table 8.2). This tool gives a near reading with 8–10 foot spacings and a far reading with 10–12 foot spacings (Figure 8.4*b*). Because of its length, the long spaced sonic has a 'dynamic' compensation system where depth

(a) BOREHOLE COMPENSATED SONIC LOG



(b) LONG SPACING SONIC LOG

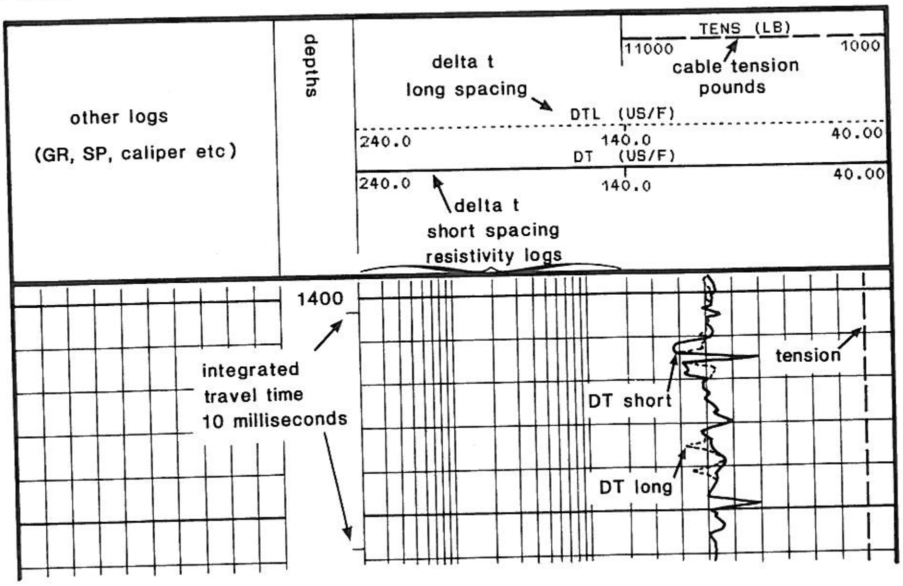


Figure 8.5 Typical sonic log headings. (*a*) BHC tool; (*b*) long spacing tool (on the ISF-sonic combination of Schlumberger).

Table 8.2 The principal standard sonic tools.

Name	Mnemonic	Company
Borehole Compensated Sonic	BHC	Schlumberger
Long Spaced Sonic	LSS	
Array-Sonic (standard mode)	DTCO	
Borehole Compensated Acoustilog	AC	Western Atlas
Long Spaced BHC Acoustilog	ACL	
Compensated Sonic Sonde	CSS	BPB
Long Spaced Compensated Sonic	LCS	
Borehole Compensated Sonic	BCS	Halliburton
Long Spaced Sonic	LSS	

memorisation is employed. To complete a full compensation sequence for both the near and far readings, the tool must record a full transmitter-receiver sequence at two depth positions separated by 10 feet, the tool's compensation shift. The system is diagrammatically illustrated (Figure 8.4b).

Log presentation, scales and units

Sonic values are given in microseconds (μs) per foot (1 microsecond = 1 × 10^{-6} seconds). The value is called the *interval transit time* and is symbolized as Δt (Figure 8.5). The most common interval transit times fall between 40μs and 140μs: this is the arithmetic sensitivity scale usually chosen for the log (Figure 8.5*a*). The velocity is the reciprocal of the sonic transit time, i.e., velocity ft/s = 1/Δt μs/ft. Even on logs with a metric depth scale, the transit time is mostly still given in μs/ft. The necessary conversions must be made to extract the metric velocity, thus:

$\Delta t = 40\mu s$ from the sonic log.

$$\text{Velocity} = \frac{1}{40 \times 10^{-6}} = 25{,}000\ \text{ft/sec} = 7{,}620\ \text{m/s}$$

When a sonic tool is run on its own it is presented in full-width track 2 and 3 (Figure 8.5a). If, as is often the case, the sonic log is combined with other tools, the log appears only on track 3, often with the sensitivity scale of 40μs – 140μs maintained (Figure 8.5*b*).

An *integrated travel time* (or TTI) is recorded simultaneously with most sonic logs. It represents a time derived from the average velocity of the formation logged and plotted over the vertical depth of the interval in milliseconds (10^{-3} seconds) (Figure 8.5), each millisecond appearing on the inside depth column as a bar. Each 10ms is a longer bar (Figure 8.5). Adding the milliseconds and dividing by the thickness of the interval covered gives the velocity. The TTI milliseconds may be added together to correspond to the travel times on the seismic section: seismic sections are in two-way time, that is TTI × 2.

The sonic tool is frequently run in combination with the resistivity logs (e.g. Schlumberger ISF-Sonic tool; Atlas Wireline Acoustilog-Resistivity tool). It is best run hole-centred, although modern tools may be eccentred, especially in large holes.

8.4 Log characteristics

Depth of investigation

The path of the compressional waves detected by sonic tools is essentially along the borehole wall with very little penetration, generally between about 2.5cm to 25cm (1"–10") from the borehole wall (Dewan 1983; Chemali *et al.*, 1984). The penetration is independent of receiver separation and depends on the signal wavelength; the greater the wavelength the greater the penetration. For a particular frequency therefore, penetration is greater in higher velocity formations (i.e. λ=vel/freq).

This simple picture is complicated by the observation that mechanical and chemical damage at the borehole wall can have an effect on sonic response (Section 8.6, Figure 8.21) (Blakeman, 1982). Damage can create a low velocity zone around the borehole. When this occurs, increasing the transmitter-receiver distance on a sonic tool increases the compressional wave penetration, which was the reason for the introduction of the long spaced sonic sonde. The increase in investigation occurs because the compressional wave in the damaged zone is slower than the wave in the undamaged formation. If the transmitter-receiver distances are large enough, these two waves become separated and it is the faster, deeper penetrating wave which is detected as the first arrival. For example, with borehole damage, while the standard sonde has a depth of investigation of 15cm – 25cm (6"–10"), the long spaced tool has an investigation of 38cm – 50cm (15"–20"). Consequently, a long spaced sonic has a greater chance of detecting the compressional wave from undamaged formation. In the reverse physical situation, in gas zones where the invaded formation, with fluid saturation, has a faster velocity than the virgin formation saturated with gas, a difference in penetration is still said to exist. In this case the standard sonic will have a very small investigation, 5cm (2") or less while the long spaced tool may reach 25cm (10") (Chemali *et al.*, 1984).

Through experience, however, the effects of wall damage on the standard sonic appear to have been exaggerated and the effectiveness of the long spacing sonic not demonstrated, a meaningful separation of the long and short spaced readings seldom being observed. The standard tool remains effective in most cases. In short, although there are variations, the depth of investigation of all sonic tools is small and the detected wave is generally from the immediate borehole wall or the invaded zone in permeable intervals.

Bed resolution

The vertical resolution of the sonic is the span between receivers for the borehole compensated tools and should be similar for the long-spacing tools (Figure 8.4). This is frequently two feet (61cm). Beds of less than 60cm

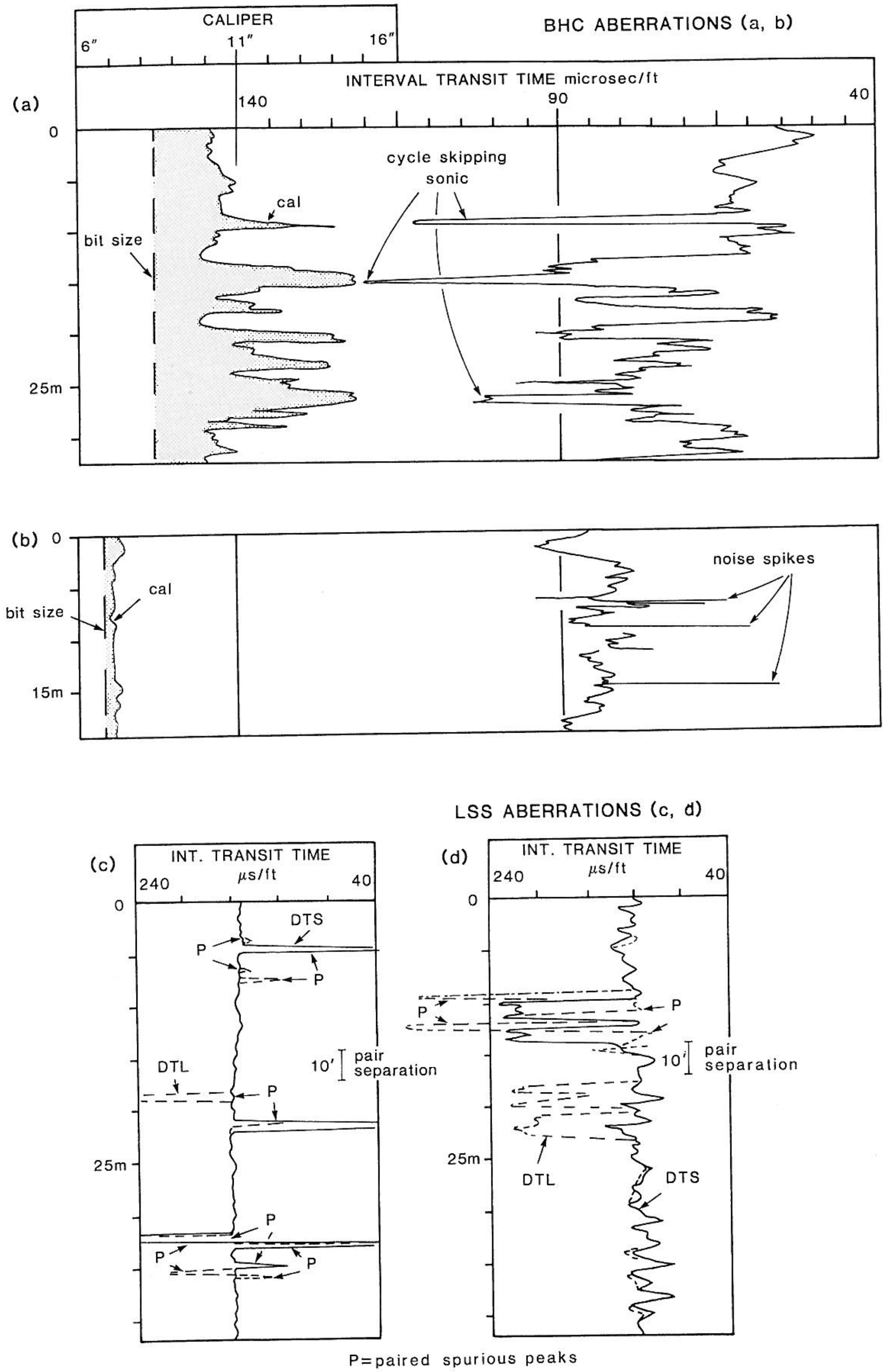


Figure 8.6 Unwanted environmental effects on the sonic log. (*a*) BHC tool, cycle skipping; (*b*) BHC tool, noise spikes; (*c, d*) long-spacing tool, paired aberrations; DTS = short-spaced sonic, DTL = long-spaced sonic. The pairs are separated for the most part by 10ft, the compensation shift distance.

thickness will be registered on the sonic log, but a true velocity will not be recorded. Specialist tools now exist with much higher resolutions (i.e. the array sonic of Schlumberger in certain modes, the digital array acoustilog of Atlas Wireline, Section 8.8).

Unwanted logging effects

The conventional borehole-compensated sonic is very robust, even in poor and over-sized holes (cf. Ellis, 1987) due to the effectiveness of the compensation system (*see* 'tools' above). However, in extremely poor holes, cycle skipping occurs (Table 8.3). This is the effect when the first, compressional wave arrival is too attenuated (weak) to activate the receiver, which is only tripped by a subsequent arrival: the recorded time is therefore too long (interval transit time too large) (Figure 8.6*a*). The reverse situation occurs when noise signals trip a receiver. This causes noise spikes on the log and is found in hard formations such as limestones (Figure 8.6*b*).

While the conventional sonic is robust, the long spaced sonic is not. There are two weaknesses in the tool which are compounded, signal attenuation and the dynamic compensation system. Attenuation results in a signal too weak to trigger a receiver, and causes cycle skipping. In the dynamic compensation system, each transmitter-receiver reading is used twice (i.e. at two levels) and an error on any one of the eight readings comprising a full sequence, causes paired errors on the log (Figure 8.6*c*). Paired errors and serious cycle skipping are frequent on many long spaced sonic recordings despite computer 'smoothing' (Table 8.3) (Purdy, 1982).

Table 8.3 Unwanted environmental effects – sonic log.

Factor	Effect on log	Severity*
Caving	'Cycle skipping' Diminished Δt troughs to a mud value (BHC) High or low or alternate paired anomalous peaks (LSS)	Present Common
Hole rugosity	'Noise triggering' Increased Δt spikes (BHC) High or low or alternate paired anomalous peaks (LSS)	Rare Common

*When the effect makes the log reading unusable.
Ratings: frequent, common, present, rare.
BHC = Borehole Compensated Sonic.
LSS = Long-Spaced Sonic.

8.5 Quantitative uses

The sonic log can be used to calculate porosities, although it is usually inferior to neutron or density-log calculated values.

To use the log it is necessary to propose that when a formation has, on average, a uniform distribution of small pores and is subjected to a heavy confining pressure, there is a simple relationship between velocity and porosity (Wyllie *et al.*, 1956).

$$\frac{1}{V}=\frac{\phi}{V_{L}}+\frac{1-\phi}{V_{ma}} \tag{1}$$

which can be written, replacing Δt for *V*, as

$$\Delta t=\phi\Delta t_{L}+(1-\phi)\Delta t_{ma} \tag{2}$$

where V = tool-measured velocity; V_L = velocity of the interstitial fluid; V_{ma} = velocity of the matrix material; ϕ = porosity; Δt = tool measured interval transit time; Δt_L = transit time of interstitial fluid; and Δt_{ma} = transit time of matrix material.

Equation (2) simply states that the transit time measured by the tool is the sum of the time spent in the solid matrix and the time in the fluid: it is called the *time average relationship* (Wyllie *et al.*, 1956). This 'time' is a function of the matrix velocity and constituents volumes (i.e. wave path length) (Figure 8.7). The relationship is best translated into graphic form, where it becomes obvious that the measured interval transit time has a linear relationship with porosity (Figure 8.8). The relationship will vary depending on the velocity of the matrix material (*see* equation 2). Some of the more common matrix velocities are shown in Table 8.4.

The quantitative derivation of porosity using the time average relationship is usually imprecise and modifications are necessary (Raymer *et al.*, 1980) although these are often only effective very locally (Brereton and McCann,

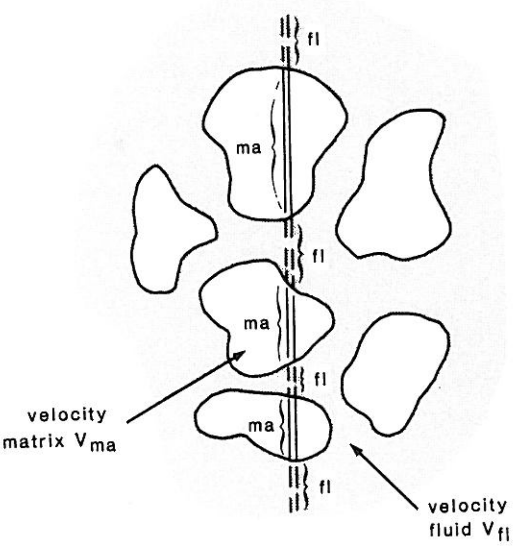


Figure 8.7 Diagrammatic representation of the path of P waves through a rock, showing the relationship between time spent in the matrix (V_{ma}) and time in the fluid (V_{fl}) giving the basis for the calculation of porosity from sonic velocities.

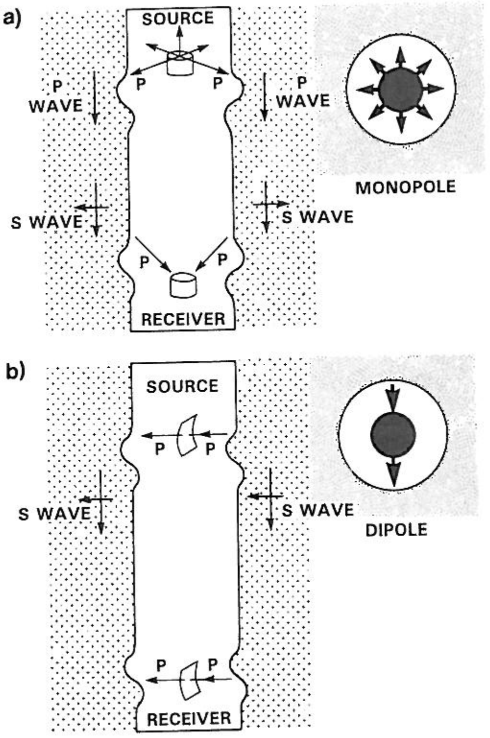


Figure 8.29 Array sonic transmitter types. a) monopole transmitter giving a multi-directional pulse; b) dipole transmitter giving a directed pulse (modified from Zemanek *et al.*, 1991).

for 8, or two for 32 waveforms and using one monopole transmitter for 8 waveforms using either a high frequency signal for P and S waves or a low frequency signal for Stoneley wave detection. The tool acquires digital waveform data with 512 samples per waveform. Logging speed varies but can be at a maximum of 1100m/hr (3600 ft/hr) which is similar to the standard nuclear tools.

All tools using an array of receivers acquire a number of receiver (or transmitter) common measurements at each depth station (Figure 8.31), the number of common datapoints depending on the number of receivers and/or transmitters used. Receiver threshold detection, as used in the standard tools, is inadequate and inappropriate for the full waveform tool. Instead, a full, digital waveform is recorded and gathering techniques are used to collect the common datapoints from a single depth (or selected interval). The gathering may be made using one transmitter position and a full receiver array (Smith *et al.*, 1991) (Figure 8.31), or a sub-array as used by Schlumberger, when several consecutive transmitter and receiver points are used (Hsu & Chang, 1987) (Figure 8.32). Sampling depths are normally the same as the separation between the receivers of the array, typically 15.24cm (6"). However, since gathering may be over an interval covering several receivers as described, the effective interval being measured depends on the gathering process (Figure 8.32), as discussed below.

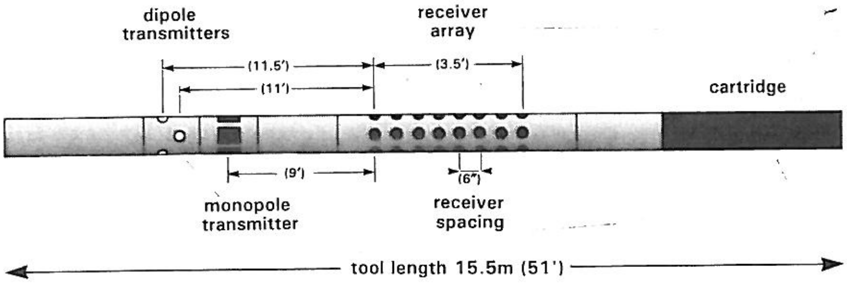


Figure 8.30 The Dipole Shear Imager Tool of Schlumberger (re-drawn from Schlumberger document).

Table 8.7 Full waveform acoustic tools.

Company	Tool	Receiver Array	Transmitters & Frequency (Fq)
Schlumberger	Array Sonic ASL	8 receivers	2 transmitters, monopole, Fq = 10–15 kHz
	Dipole Shear Imager DSI	8 receivers	3 transmitters, 1 monopole, 2 dipole Fq = 1 kHz (diopole), Fq = variable (mononpole)
Atlas Wireline	Digital Array Acoustilog DAC	12 receivers	2 transmitters, monopole, Fq = 9 kHz
	Multipole Acoustic Tool MAC	8 receivers	4 transmitters, 2 monopole, 2 dipole Fq = 1–3 Hz (dip), Fq = 8 kHz (mono)
Halliburton	Full Wave Sonic Log FWS	4 receivers	1 transmitter, monopole, Fq = 13 kHz

Data output, velocity picking

With a full, digital waveform from all of the receivers in an array at each sampling depth, separating the various wave arrival times and slowness values requires special processing. For example, the output from an eight receiver array provides 8 waveforms with different offsets (Figures 8.31, 8.33*a*). To derive the separate P, S and St wave velocities (slowness) various methods are used comparable to stacking in seismic processing (Block *et al.*, 1991). Effectively, the data from the individual traces are combined in such a way as to enhance individual wave information and diminish noise or other unwanted effects. Typically, at each depth, a map in a time-velocity domain is produced (Figure 8.33*b*) from which individual wave slowness values can be picked and a log of slowness against depth produced.

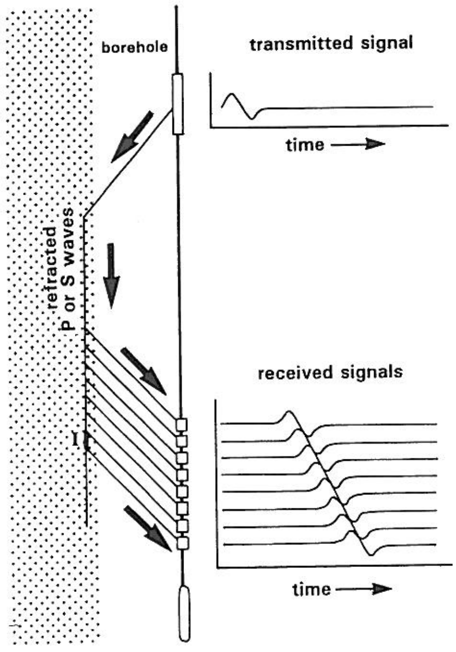


Figure 8.31 Array sonic sampling system. At any depth, a series of transmitter common readings are made, with different offsets. Sequences of readings are gathered in various ways (*see* text and Figure 8.32) (from Smith *et al.*, 1991).

A complication arises using tools with only *monopole* transmitters in 'slow' formations where the shear energy and the Stoneley energy cannot be separated. In order to have shear velocity with this data, it is modelled from the Stoneley information and an *interpreted* shear arrival is given. With the *dipole* transmitters, direct detection of the shear arrival is possible in both 'fast' and 'slow' formations, as indicated above.

The resolution of the array tools is related to the array size used in the processing gather or the gather technique. This will be the vertical height of the array or 1.07m (3.5ft) for the DSI of Schlumberger (Figure 8.32). A bed thinner than the array gather will still be indicated and in its real depth position, but it will not be fully resolved (Hsu and Chang, 1987). Generally, all the receiver information will be included in one gather and borehole compensation may be applied by using transmitter stations through the receiver array section (Figure 8.32*a*).

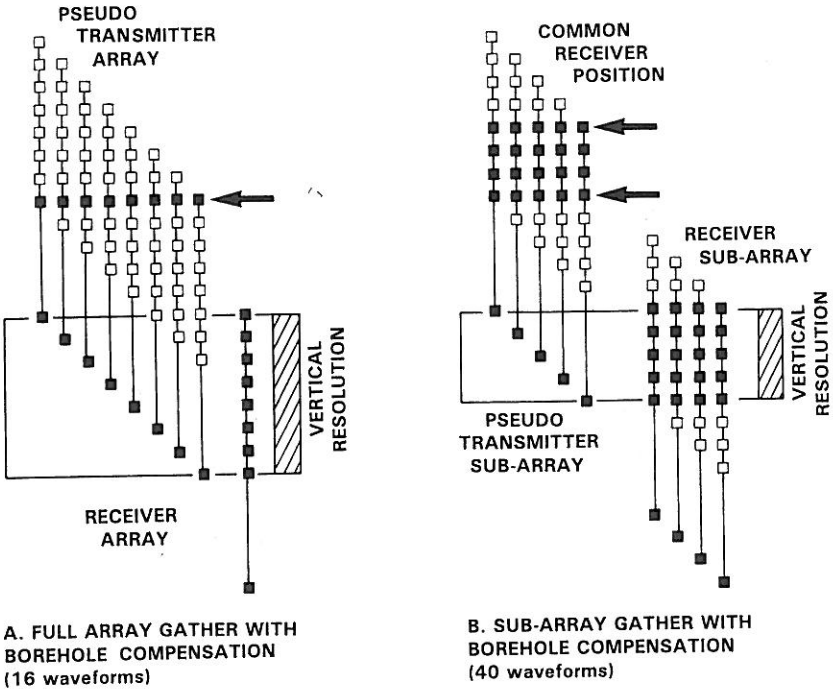


Figure 8.32 Data gathering methods for the array sonic used by Schlumberger. A) gather using one transmitter position and an array of 8 receivers. B) gather using 4 transmitter positions and an array of 5 receivers. The vertical resolution of the measurements will be the vertical height of the array or sub-array (re-drawn modified from Hsu and Chang, 1987).