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Niranjan C. Nanda

Seismic Data Interpretation and Evaluation for Hydrocarbon Exploration and Production

A Practitioner's Guide

Second Edition

Springer

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Preface

The first edition of the book was published in March 2016. It was intended for postgraduate students of geoscience and young professionals engaged in the petroleum industry as an aid in understanding the fundamentals of seismic data interpretation and evaluation and their application in petroleum exploration and exploitation. For an effectual evaluation of data, a seismic analyst needs familiarity with the basics and working knowledge of various disciplines such as geophysics, geology, geochemistry and reservoir engineering. These days students and young professionals come well-armed with the basics in their respective disciplines. What this book intends to present is an organized and cogent template for a systematic and synergetic approach to synthesize the multidisciplinary data which can help in the quest for finding more hydrocarbon reserves. While the preliminaries are mostly kept to the bare minimum, the emphasis in the book has been on the interpretation workflows and practices, traditionally followed in the industry. These are briefly discussed in simple and practical ways, interspersed with ample illustrations and case study examples, along with the problems that are commonly encountered. However, my experience over the past several decades in terms of interactions with students and practicing young interpreters at work as well as the feedback received from many readers prompted me to expand some of the themes a little more explicitly and add some material anew to come out with publication of the second edition of the book.

The book was earlier structured principally with two modules, namely exploration seismic and reservoir and production seismic, primarily involving conventional reservoirs. However, with the global attention leaning more towards exploring and exploiting unconventional reservoirs, a major addition in this edition is the third module which comprises the unconventional reservoirs under the heading 'Unconventional Reservoirs Exploration and Production—The Role of Seismic'. Three additional chapters under this module focus on oil sands, heavy oil, tight oil and gas sands, basin-centred gas accumulations (BCGAs), coal bed methane (CBM), shale oil and gas, gas hydrates and fractured-basement reservoirs. These topics are discussed succinctly to create awareness. Since most unconventional reservoirs are incapable of producing hydrocarbons under primary recovery, exploitation through secondary and enhanced recovery methods is also outlined. More importantly, the role of seismic in exploring and exploiting these unconventional reservoirs and in monitoring the recovery processes for efficiency is also included.

Almost all chapters in the book are expanded with more explicit explanations and addition of new subject matter. Some of the noteworthy inclusions are the concept of rock microstructure, its physical and mechanical properties, anisotropy and building mechanical earth models (MEM). Other interesting additions are polarity display conventions linked to energy source wavelet, instantaneous velocity and velocity modelling, geochemical analysis and evaluation of hydrocarbon source and generation, tomography and microseismic surveys, depth conversion vis-a-vis prestack depth migration (PSDM), pore-pressure prediction, AVO modelling, phase rotations for zero-phase 3D data and thin-bed reflectivity inversion. The author strongly believes that graphics, sketches and image illustrations with explicit captions expound the concepts better than the descriptive scripts in texts. Accordingly, many more illustrations and case examples are included in this new edition.

Lastly, the limitations of seismic technologies and techniques are underscored with more examples of failures and pitfalls, an aspect which usually remains unreported or underreported in the industry. Pitfalls are an intrinsic part of seismic interpretation along with serendipity, though the latter is always welcomed due to encouraging breakthroughs, the pitfalls are spurned for causing setbacks. Nonetheless, it is hoped that the new edition of this book provides enough fodder to the inquisitive and sharp minds of professionals for improving their imaginative skills and work practices, which hopefully will help them excel in their quest for finding more hydrocarbon through cognitive seismic data evaluation.

Cuttack, India Niranjan C. Nanda
March 2021

Acknowledgements

A few years ago, persistent persuasion of my good friend and erstwhile colleague at ONGC, Satinder Chopra, Arcis Seismic Solutions, TGS, Calgary, Canada, compelled me to author the book titled *Interpretation and evaluation of seismic data for Hydrocarbon Exploration and Production—A Practitioner's Guide*, which was published by Springer in March 2016. Over these ensuing years, my work association with young seismic interpreters and feedback from several readers encouraged me to cover fresh ground which may seem elementary but I believe is essential for seismic analysts to become more effectual. Once again, Satinder obliged by playing a major role in expounding several concepts through personal correspondences and most importantly in providing excellent graphics and images for illustrations used in this edition. Understandably, without his help, the second edition of the book would not have been possible. I express my indebtedness and profound gratitude to Satinder for his help and support.

I thankfully acknowledge ONGC, India, Arcis Seismic Solutions, TGS, Canada, Society of Exploration Geophysicists (SEG), European Association of Geoscientists and Engineers (EAGE), American Association of Petroleum Geologists (AAPG), Canadian Society of Exploration Geophysicists (CSEG), Alberta Geological Survey (AGS) and GeoExpro and USGS for permitting the use of several graphics and images in the book. My thanks are also due to the individual authors, Tako Koning, Ray Bosewell, Ross Crain, M. Kurihara and Jane Whaley who accorded permission for use of their illustrations in my book. I would also like to express thanks to my young friend Ravi Kumar of Saturn Energy Solutions, Hyderabad, India, who helped me with reworking and improving some of the figures and images for inclusion in the book.

I sincerely thank Springer publishers for their dexterous handling of the manuscript for print.

Finally, I wish to gratefully acknowledge the support and care my wife extended during the difficult time of the COVID pandemic. Her patience and steadfast encouragement to continue was an inspiration, for which I remain indebted forever.

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March 2021

Contents

Exploration Seismic

Seismic Wave and Rock-Fluid Properties

Abstract

Seismic rock physics is study of seismic response of rock and fluid properties, used essentially to help predict reliably the lateral and vertical variation in rock properties in the subsurface from seismic data. This would entail knowing basics about seismic wave and its propagation in the earth and the different rock and fluid properties that impact seismic properties. Seismic waves are elastic waves and suffer loss of energy of different kinds while propagating through rock layers having different rock properties in the earth. The propagation mechanisms, the losses and their geologic significance are described.

The intrinsic seismic properties are the amplitude and velocity which are influenced by properties of rocks through which the wave travels. The elasticity and density of rocks primarily determine the seismic amplitude and velocity, though several other rock and fluid properties such as porosity, texture, fractures, fluid saturation, viscosity and factors such as pressure and temperature also affect the seismic properties. The microstructure of rock, its elastic, physical and geomechanical properties and their seismic responses, known as seismic rock physics studies are deliberated.

Descriptions of homogeneous, heterogeneous, isotropic and anisotropic rocks and seismic anisotropy, Gassmann's equation and fluid saturation, normal, abnormal and pore pressures are dealt to elaborate the seismic rock physics studies. Seismic rock physics modelling (RPM) and mechanical earth modelling (MEM), their utilities in seismic rock physics application along with limitations are mentioned.

Focusing on geologic interpretation of seismic data before introducing fundamentals of seismic principles and rock physics can be something like putting the cart before the horse. Therefore, this chapter is a revisit to the basics of seismic wave propagation and related rock physics. It answers briefly some of the important questions, as given below, which ultimately guide interpretation.

- *How do seismic waves propagate through rocks?*
- *How is seismic energy attenuated?*
- *What are fundamental wave properties?*
- *What are rock-fluid properties and how do they affect seismic response?*

Seismic Wave and Propagation

A seismic wave is an elastic wave traveling through a solid rock. When a rock is subjected to a pressure wave, its particles get displaced, transferring energy to the adjacent ones causing a seismic wave to propagate onwards in the rock

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through particle motions. There are two types of seismic body waves that travel in solid rocks; longitudinal (primary or compressional) waves and transverse (secondary or shear) waves. In fluids, however, only the longitudinal waves can travel.

A seismic wave propagating in the earth encounters several discontinuities (boundaries) between rock types of different physical properties and produces phenomena such as reflections, diffractions, absorptions, scatterings and transmissions (refractions). At each boundary or interface between two different types of rocks, a part of the incident energy is reflected back to the surface and the rest of energy is transmitted to the underlying rocks. Seismic methods for exploration of hydrocarbons mostly use the reflected energies of primary or compressional waves returning to the surface. Shear waves reflections are also recorded but are used in specific cases, to provide valuable support to subsurface information. Chapter "Shear Wave Seismic, AVO and Vp/Vs Analysis" (Shear Wave Seismic) provides more detailed discussion on shear seismic. As the wave energy (seismic pulse) travels downwards in solid media, it undergoes gradual loss of energy (attenuation) depending on the rock-fluid properties. Attenuation, a natural phenomenon, comprises of several types of losses and understanding the process behind each loss can be useful in interpreting the rock type.

Energy Losses

Absorption

The seismic source wave, generated at the surface, as stated earlier, propagates through a rock by transferring energy from one particle to another. In the process, a part of the energy is attenuated due to conversion of mechanical energy to heat energy through frictions at grain contacts, cracks and fractures and fluids present in pores of a rock. The frictional loss, primarily due to motion between rock particles at the point of grain contacts, is known as absorption. Frictional loss is also sensitive, to a lesser extent, to fluid properties like saturation, permeability and viscosity as the wave travels through sedimentary rocks which are generally saturated with fluids. Absorption in rocks is related to the first power of frequency whereas in liquids it is related to square of the frequency (Anstey 1977)

Absorption is called anelastic attenuation which is frequency selective and cuts out higher frequencies progressively from the source pulse as it travels down. This results in reduced energy with a wavelet of lower frequency and lower amplitude at deeper depths (Fig. 1). Absorption effects are severe within shallow weathering zones and decrease with depth. Magnitude of absorption (friction) loss in a hard rock is liable to be much higher than that in a fluid saturated rock as friction in fluid, which is a slushy medium, is likely to be marginal (Gregory 1977). For instance, seismic data in offshore deep waters hardly ever show low- frequency domination which support that little or no energy is lost due to absorption in water column. However, there can be some absorption loss in partially saturated hydrocarbon reservoirs due to viscous motion between the rock and the fluid during the wave propagation.

Scattering

Scattering loss is a frequency dependent *elastic* attenuation linked to dispersion, a phenomenon in which velocities in rock measure differently with varying frequencies. Scattering losses are irregular dispersions of energy due to heterogeneity in rock sections, and are usually considered as apparent noise in seismic records. Scattering and absorption losses are sometimes referred to as attenuation. Geological objects of very small dimensions tend to scatter wave energy and produce diffractions rather than continuous reflections. Highly tectonized shear zones with faults and fractures, very narrow channels, pinnacle mounds etc., are some of the geologic features, most prone to scattering effect.

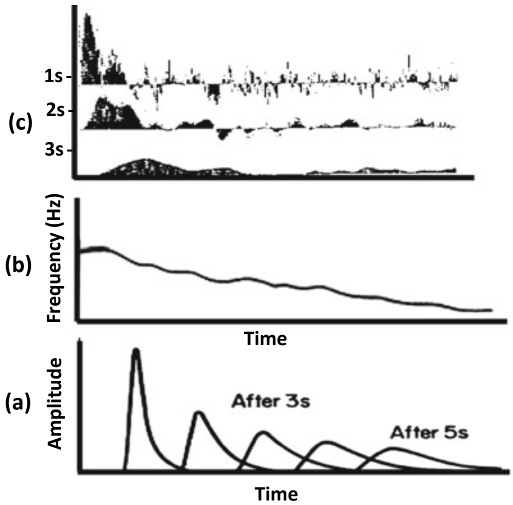

Fig. 1 Schematic showing energy loss due to absorption during propagation of a wave (**a**) time domain showing lowering of amplitude and frequency (wave-width broadening) with time (**b**) frequency domain showing loss of high frequencies progressively with time and (**c**) the over all look of a seismic trace with time (modified after Anstey 1977)

Transmission

Transmission loss is loss of energy the wave undergoes at every lithologic boundary, as a part of the energy is reflected back to the surface allowing less to go deeper. The energy loss at depth thus depends on the type and number of reflecting interfaces. It is sometimes believed that a strong reflector like a limestone or an intrusive body reflects most of energy upwards and transmits less in the process, causing poor reflections or shadows below. However, Anstey (1977) has demonstrated that strong reflectors may not be the sole reason for large transmission losses. Instead, such effects may be caused due to large number of thin layer interfaces, which even with small reflectivity but alternating signage of contrasts can create as many reflections to account for energy loss.

Transmission losses reduce amplitudes at all frequencies and are not frequency selective as in absorption. One positive spinoff of wave transmission through several thin beds can be the causal peg-leg multiples from several thin beds which through constructive interference can create considerable reflection amplitudes to be noticed on seismic. Peg-leg multiples are intrabed short-path asymmetrical multiples generated from thin beds within a formation (Fig. 2). However, addition of several reflections tends to lower the frequencies, giving an appearance of a pulse similar to the absorption effect. Prima-facie, it may be, hard to distinguish the effects on a seismic pulse due to absorption and transmission losses.

Spherical (Geometrical) Divergence

Seismic wave, ideally considered travelling in the form of spherical wave front, suffers from reduction of energy as it continually moves away from source and spreads through the subsurface rocks with time (distance). This is also known as geometrical loss as it is linked to the wave-path geometry. The decay is dependent on distance from the source and increases with higher velocities due to greater distance travelled (Fig. 3).

Geological Significance of Energy Attenuation

Large attenuation losses in rocks, besides the amplitude, also lower the frequencies of seismic wave which lead to show lower velocities due to dispersion effect. Measurement of both attenuation and velocity can therefore provide complimentary information about the rock and fluid properties. Further, attenuation affecting the frequency and the amplitude content of the wavelet also results in changing the seismic wave shape. Analysis of propagation loss in rocks from the resulting changes in wave shapes can then lead to important geological information about rock and fluid properties. Some significant geologic conclusions from analysis of attenuation effect can be as below.

- Indication of high energy loss considered owing to absorption, may give a clue to the

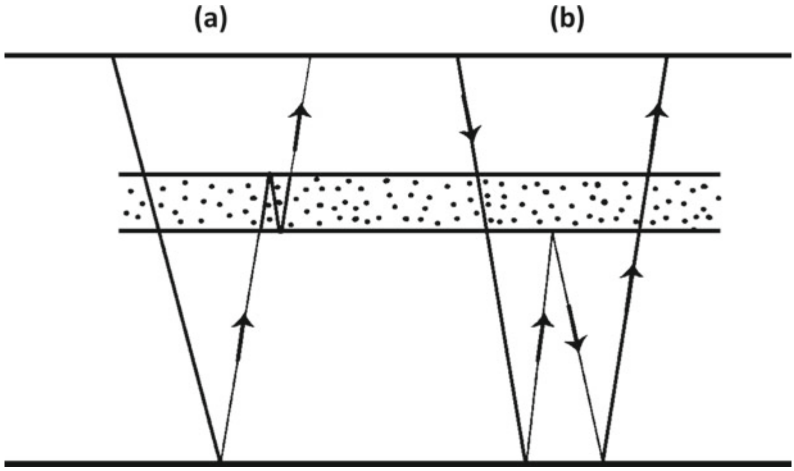

Fig. 2 Schematic illustrating peg-leg multiples, (**a**) multiples from within and (**b**) from bottom of a thin layer, embedded in a formation. Note the typical asymmetrical short-path multiple in (**a**) which impacts greatly the reflection quality when multiple thin beds are involved

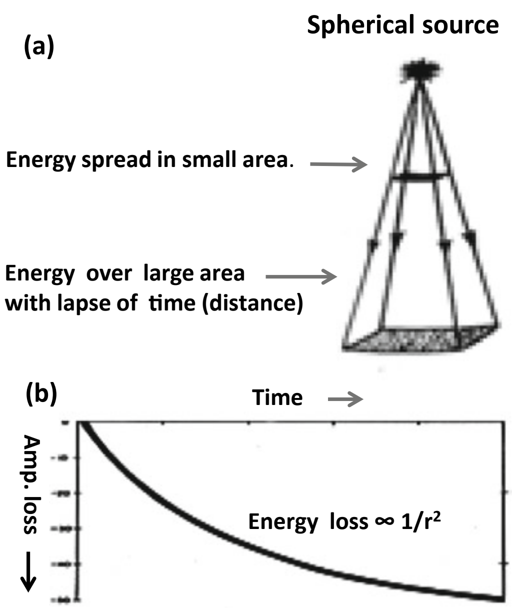

Fig. 3 Loss due to spherical divergence during seismic wave propagation. (**a**) spreading of spherical wave causes loss as the energy is distributed over larger area with passage of time and (**b**) is proportional to distance travelled (modified after Anstey 1977)

type and texture of the reservoir rock. Unconsolidated, fractured, and poorly-sorted rocks having angular grain contacts are likely to have considerable friction (Anstey 1977). On the other hand, rocks, well-sorted and with well-cemented pore spaces will show less loss due to absorption.

- Seismic evidence of high transmission loss can be suggestive of a formation consisting of cyclically alternating impedance contrasts such as in multiple thin sand layers occurring with intervening shale layers, the *cyclothems*, often typically deposited in deltaic environment. *Cyclothems* are potentially important geological plays that are commonly sought after by the explorationists.
- Scattering losses due to heterogeneity in strata may provide clues to order of irregularities in reservoirs suggesting rapid facies change such as in continental depositional environments. Similarly, scattering losses resulting in poor to no seismic reflections may indicate presence of fault and fracture zones, *mélanges* in highly tectonized zones of subduction. Seismic survey in such areas would need suitable planning of acquisition and processing techniques to achieve better seismic images.

However, types of energy losses are difficult to distinguish and determine in real field situations. Can the losses due to absorption be distinguished from those due to transmission, which cause similar effect on a wave pulse? This can be answered to some extent during data processing workflow, but usually the interpreter has little time or access to dig into data processing, that also requires special efforts to identify and quantify losses. Nevertheless, under certain favorable situations, such as in known geologic areas, relatively shallow targets of exploration, in high resolution offshore marine data, it may be possible to detect some of the losses through special processing techniques. This assists in interpreting type and texture of rocks, albeit, qualitatively.

Seismic Properties

Seismic response to rock-fluid properties consists of the important intrinsic properties of seismic wave and is indispensable in the framework of exploration seismic technology. The primary properties of a seismic wave are (1) the seismic amplitude of the wave and (2) the velocity of the wave. Seismic amplitudes are the particle velocities measured by the geophones on land or the acoustic pressure by hydrophones in marine streamer surveys and velocity is with which the wave passes through the rocks. Particle velocity conveys the magnitude of the seismic disturbance (micrometers/sec) whereas wave velocity conveys the speed of the seismic disturbance at which it travels (km/s). Amplitude and velocity are the two seminal seismic properties that constitute the response and differ over a wide range, dependent on rock-fluid properties.

Seismic wave propagation in subsurface and its attendant effects brings out vital geological information about different types of subsurface rocks and their fluid contents. The rock-fluid properties, which are many, affect seismic response and can be intricately complex to decipher. Fortuitously, most of the rock-fluid properties influence one way or another the two primary physical properties of a rock, the elasticity and the density, which determine the seismic responses by amplitudes and velocities of waves. The amplitude of a seismic wave, is a function of contrasts between two impedances (a product of velocity V and density ρ) of rocks at an interface. Seismic velocity (V), on the other hand is a function of elastic modulii (E_m) and density (ρ), expressed by the equation

$$V = \sqrt{(E_m/\rho)},$$

Both compressional (P) and shear (S) velocities are influenced by rock properties albeit differently. However, the rock-fluid properties affecting mostly the P-seismic properties are discussed here while the S-seismic properties are dealt later in Chapter "Shear Wave Seismic, AVO and Vp/Vs Analysis" (shear seismic).

Having introduced the seismic properties, what are the rock-fluid properties that directly or indirectly affect the seismic properties?

Rock-Fluid Properties

The rock properties may be considered of two kinds, the physical rock properties and the mechanical rock properties, the latter mostly used for engineering purposes. Physical properties of rocks in the context of hydrocarbon exploration, also include properties of fluids that occupy rock pores. These are essentially the elastic modulii, density, porosity, anisotropy, fluid type and saturation and factors such as pressure and temperature, which impact seismic response. Mechanical properties, on the other hand, are the strength, stiffness and toughness of rocks in response to applied stress which can deform or induce changes in behavior of rock and cause changes in seismic response are studied under Geomechanics, described later in the chapter.

Seismic Rock Physics and Petrophysics

Seismic rock physics is the link between the rock and seismic properties, the cause and the effect. Knowledge of seismic rock physics provides a unique advantage in that seismic data can be used as predictive models for estimate of rock properties in petroleum exploration and production applications. Seismic rock physics may not be mixed up with petrophysics as there are several points of differences. Seismic rock physics is primarily utilized by geoscientists while petrophysics is used by log analysts. While seismic interpreters mostly use sonic and density logs to estimate rock properties, the petrophysicists use all kinds of log data in the complete log suite, together with core and production data. Whereas the seismic interpreter typically requires the logs for rock property evaluation, the log analysts may not need seismic data for the purpose. More prominently, petrophysics is a more elaborate and finer study of rock properties done in microscopic scale (mm-cm) in contrast to seismic studies in macroscopic scale (10–100 m). Consequently, seismic rock physics modeling (SRM) from seismic analyst point of view can be quite different from Petro physicist's angle.

Rock Microstructure

Since rock and fluid properties determine the seismic response, inversely, they can be interpreted from seismic data. In this context it is important to elaborate microstructure of a rock whose elements individually impact seismic properties. *A* rock is essentially described in terms of its framework and matrix, cement, pore space and fluid content. The framework or the skeleton comprises the coarse grains of detritus sediments whereas matrix is the very fine filling material in the space between the framework grains. Cement, on the other hand, is a secondary mineral that forms after deposition and during burial of rock that binds the framework grains together. The other important element in the pore space, the void available within a sedimentary rock, saturated with fluid (Fig. 4). All the elements that constitute a rock ultimately influence elasticity and density of a rock, and it is expedient to consider the effect of each individual element of the rock and fluid properties separately on elasticity and density to conclude their net impact on seismic response. Though the elastic moduli of rocks depend predominantly on the moduli of rock matrix, pore geometry and the elastic moduli of pore fluids, the impact of other elements, comprising the rock microstructure are small can yet impact response considerably if they are combined to add.

Many other factors besides the rock and fluid properties such as pressure, temperature and anisotropy also considerably affect seismic properties. From the large number of rock and fluid properties that influence seismic properties, we restrict our studies limited to the usually the important ones as below that cause perceptible seismic response.

Physical Properties of Rocks

Elasticity and Elastic Constants

Elasticity of a rock is defined as the resistance it offers to stress. There are three principal elastic modulii, namely Young's modulus (E), bulk modulus (k) and shear modulus (μ). In homogeneous isotropic media, simple relations exist between these three and can be determined if any two modulii are known. Other elastic modulii such as Poisson's ratio (σ) and lambda can be determined from the three principal modulii. Lambda and Mu are known as Lame's constant. Lambda is considered a fluid indicator and can be derived from bulk (K) and shear modulii (μ) but its application is less common. The Young's modulus (E) and the Poisson's ratio (σ) and their applications are discussed under mechanical properties later in the chapter.

However, the two principal elastic moduli controlling seismic responses are the bulk modulus (k) and the shear modulus (μ). Bulk modulus is a measure of a rock's resistance to change in volume, its incompressibility and shear modulus, also known as modulus of rigidity, is the measure of resistance to deformation by shear stress, its rigidity. Depending on the type of wave, compressional or transverse, specific elastic modulii play the dominant role in determining the seismic velocity. In case of compressional waves (P-waves), both bulk modulus and shear modulus control seismic velocity and for shear or transverse waves, only the shear modulus plays the dominant role in controlling S-velocity. In an isotropic media, compressional

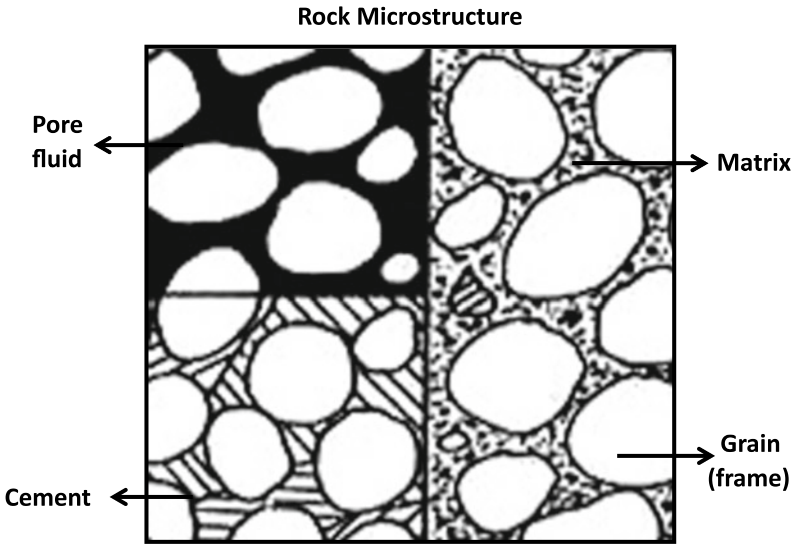

Fig. 4 A schematic showing the micro structural elements of a sedimentary rock: the framework comprising coarse grains, the matrix (very fine interstitial fills), cement formed post deposition (diagenesis) that binds the grains together and the pore voids filled with fluid. Each of these elements contribute to the total impact the rock creates on seismic response

and shear wave velocities are given by the equations

$$Vp = \sqrt{[(k + 4/3\mu)/\rho]}, and$$
$$Vs = \sqrt{[\mu/\rho]},$$

One simple way to comprehend the elastic moduli of a rock is its hardness. A hard rock is difficult to compress because of high bulk (incompressibility) and high shear modulus (rigidity), and shows increase in P- and S-seismic velocities. Likewise, a soft rock with a large compliance has lower elastic modulii and consequently exhibits lower velocities. In a geological sense, elasticity may be likened to a measure of the hardness of a rock, which depends on lithology which commonly increases with depth.

Bulk Density

Bulk density of a sedimentary rock includes the density of the rock matrix and the density of the fluid in the pore spaces. Density of a rock is defined as its mass per unit volume and commonly increases with depth. It is a result of compaction, as the rock undergoes burial, the pore voids get compressed and the rock gets denser (Fig. 5). Compaction is a diagenesis process that squeezes out water from the pore space of sediments with time (depth) by overburden pressure as they get buried beneath successive layers of sediments. Compact rocks show higher densities whereas under-compacted formations demonstrate lower density values. It may seem paradoxical that compact rocks at depth, though have higher bulk density, yet show higher velocities. This is because of relatively higher increase in elasticity of the compact rock than the increase in density with elasticity playing the dominant role in determining the velocity. It also may be stressed that velocity and bulk density are not directly related, though empirical equations exist which allow estimation of compressional velocities from bulk densities but limited to certain stipulated conditions, such as water-saturated and normally pressured sedimentary rocks (Gardener and Greogory 1974). Nonetheless, density determination from seismic remains a difficult task.

Porosity, Pore Size and Shapes (Pore Geometry)

Porosity is a measurement of the void space in a given volume of rock. In general, an increase in porosity lowers the density (Fig. 5) and more so the elasticity of a rock which results in decreasing the seismic velocity, more conspicuously the P-velocity. Though there is an established relation between porosity and density, no such

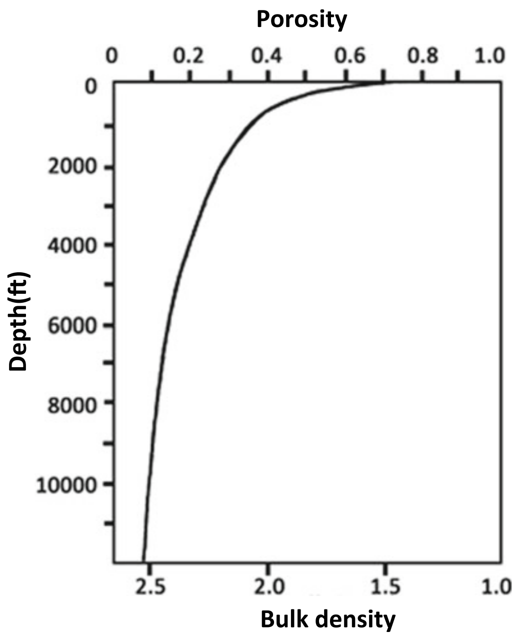

Fig. 5 Graph showing density increase with depth due to compaction of rock (diagenesis) in normal pressured sections. Compaction leads to reduction in pore voids, lowering the porosity resulting in increase indensity (after Anstey 1977)

definitive relation exists between porosity and velocity (Anstey 1977). Porosity and pore shapes are found to vary greatly in different kinds of rocks. Porosities are of two types, primary and secondary. Primary porosity is the pore space that occur between the grains in a sedimentary rock and are also known as intergranular porosity, as is seen in unconsolidated sands and partially cemented pores of sedimentary rocks. Secondary porosity, on the other hand, is pore space that has developed later on after the rock is formed. This may be caused due to fractures, weathering related leaching, solution channels and vugs linked to water ingression. Cemented sands and tight carbonates often exhibit void spaces because of fractures and cracks which are secondary porosities and are called fracture porosity. Similarly, the other types of secondary porosities depending on their causatives are known as leached, solution and vuggy (cavernous) porosities, mostly common in carbonate rocks. The type and order of porosity, controlled by the pore geometry, determine the seismic properties, the velocity and density generally decreasing with increasing porosity.

Nevertheless, an empirical time-average equation (Wyllie et al. 1956) provides a basic link between primary porosity and velocity that is often used in interpretation.

$$1/V_r = 1 - \phi/V_m + \phi/V_f ,$$

where, V_r, V_m & V_l are velocities of the whole rock, rock matrix and liquid content in pore space, respectively and φ is porosity. It is known as time-average equation as the total time taken for a wave to travel in the rock is assumed to equal the sum of travel times in each rock component (Fig. 6). The time-average equation, however, has, several limitations such as particular types of rock with specific properties that include degree of porosity, type of fluid and normal pressure amongst others. It can be used to reasonably predict intergranular porosity of highly porous, water and brine saturated sandstones under normal pressure (Gregory 1977; Anstey 1977) but may not be applicable for highly porous gas saturated unconsolidated sands and in over-pressured regimes. The equation has since undergone several modifications (Raymer et al. 1980; Wang and Nur 1992) for present applications.

Pore geometry defines the distribution of voids and their size and shapes and is dependent on geometry of the grains of detrital sediments during deposition (Tatham 1982). The pore shapes can be of several types, ellipsoidal, spherical and penny-shaped, and are commonly described by the parameter, the aspect ratio which is the ratio of small to long axis of the pores. For flat penny shaped voids the aspect ratio is less than one and for spherical pores it is one. Rocks with flat pore shapes with small aspect ratio are amenable to higher compressibility and generally show lower velocity than those with large value aspect ratio such as with spherical pores. Pore shapes significantly impact behavior of P-velocity and sometimes more than the degree of porosity, per se. For instance, a reservoir with relatively lower porosity with flat

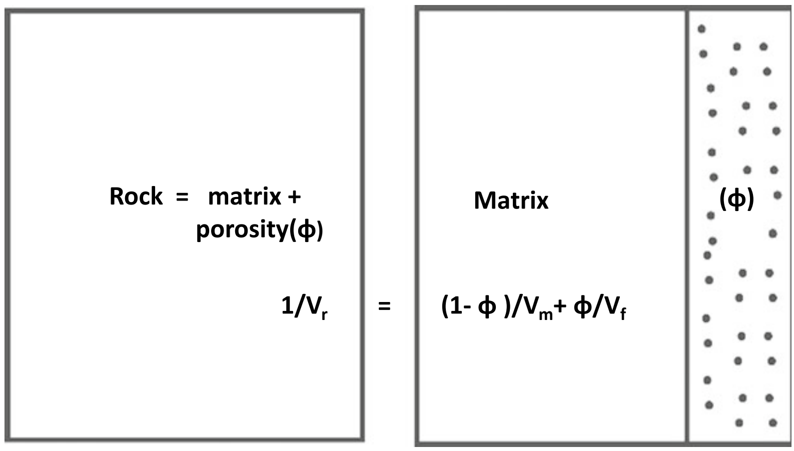

Fig. 6 Schematic illustrating the Willey's 'time average equation', linking velocity and porosity of a rock. The total time taken for a wave to travel in a porous rock is assumed to be equal to the sum of travel times in the two principal components, i.e. the matrix and the pore space filled with fluid

and low aspect - ratio pores may indicate lower seismic velocity than a highly porous reservoir with high aspect-ratio such as the spherical pores (Wang 2001). Though impact of pore geometry in velocity may be considerable, it remains a difficult parameter to quantify from seismic.

Texture

Grain sizes, roundness, sorting and cementation commonly describe the texture of a rock. Elasticity and density of a rock depend on contacts between the grains, their size and angularity though the latter ceases to play a role after the rock is cemented. Large grain sizes and compact sands have generally higher seismic properties due to larger contact areas causing higher velocity (elasticity) and density, whereas, unconsolidated sands with angular grains show lower seismic properties (Wang 2001)

Fractures and Cracks, Geometry

Seismic properties are affected considerably by presence of fractures (open) and cracks in rocks. Open fractures and cracks are considered different from void spaces like pores, caverns and vugs because their impact on elastic properties is disproportional to the much smaller volume of pore voids. Fracture porosities are commonly less than 2% (Gurevich et al. 2007) but can affect seismic velocity considerably. Fracture and crack geometry is more complicated than pore geometry; in addition to flatness, size and shapes of voids, it needs other parameters such as length, orientation and density of the fracture and cracks and their distribution to define the fracture geometry fully.

Fractures and cracks usually facilitate compressibility (compliance) and considerably lower the velocity and impedance of rocks. Though fractures and cracks are known to impact significantly the seismic properties, it may be difficult to predict their geometry from seismic response. For instance, in a given volume of a fractured carbonate reservoir having a specific bulk density, similar fracture porosity can be expected either by assuming a large number of microfractures or by fewer numbers of bigger fractures. Even though the fracture porosity remains same, the velocity can be much lower in the former case compared to the latter (Anstey 1977). Sayers (2007) also indicated that the seismic response may be same for a small number of highly compliant fractures as for a large number of stiff fractures. This can have a significant implication on reservoir evaluation as the micro fractures linked to lower velocity may not be indicative of better permeability than the reservoir having larger fractures.

In case of cemented fractures, seismic velocity may indicate much higher values compared to what is expected at that depth. Such anomalous high velocities for a rock in a known tectonic area may corroborate the presence of fractures predicted from geologic data but it also offers a clue that the fractures are not open and may be cemented. Similar to pore shape geometry,

geometry of cracks and fractures with varying aspect ratio, too affect the seismic properties intricately and for flat-shaped fractures being significantly lower. The number and shape of fractures also determine the elasticity (compliance) of a rock which primarily decides the seismic properties, the velocity and amplitude. Another important aspect of fractures is causing anisotropy in a rock leading to azimuth dependent seismic properties discussed later. It also causes direction dependent wave attenuation and scattering linked to induced heterogeneity in the rock created by contrasts in elastic properties of open fractures with the surrounding rocks.

Anisotropy

A rock medium is considered anisotropic when the properties vary depending on direction of measurement. It is a vectorial variation of a physical property dependent on direction from a point and is different from heterogeneity which is a variation of property in scalar values limited to its position in a medium. Anisotropy induces heterogeneity in a rock but the reverse may not be always true; heterogeneity may not be a necessary condition to create anisotropy in a rock. A simplified concept of the rock properties, heterogeneous, homogenous, isotropic and anisotropic is illustrated in Fig. 7.

Anisotropy in rocks is linked to stress and is commonly of two kinds, intrinsic and induced (Wang 2001).

- Intrinsic anisotropy is an inherent property of a rock caused by preferential alignment of grains and layering as in shale sedimentation. This is referred as VTI (vertical transverse isotropy), as it is associated with the vertical dominant stress, the gravity.
- Induced anisotropy in a rock, on the other hand, is caused by fractures and cracks and is referred as HTI (horizontal transverse isotropy), as it is associated with regional horizontal stress.

Seismic anisotropy is defined as direction dependent seismic velocity in a rock. Anisotropy affects both P-and S-wave velocities, though differently, being less perceptible in the former. In an intrinsic anisotropic medium (VTI) such as

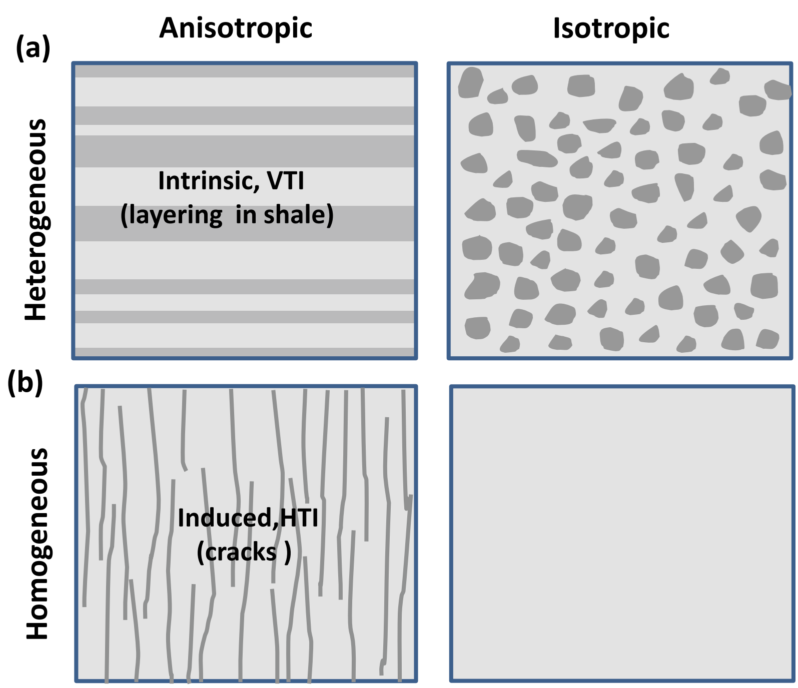

Fig. 7 Simplified conceptual diagram showing heterogeneous, homogeneous, anisotropic (transverse isotropic) and isotropic rocks. Note (**a**) the intrinsic anisotropy nature of heterogeneous shale and (**b**) the induced anisotropy by cracks in the otherwise homogeneous rock (courtesy Satinder Chopra, Calgary)

shale, the P-velocity is faster along the layered bedding planes than in the vertical direction (Fig. 8a). Similarly, in an induced anisotropy medium (HTI) such as in fractured rocks, P-and S-velocities travelling parallel to fracture plane are faster than those travelling across (Fig. 8b). However, variance of seismic velocity with azimuth, also termed as azimuthal anisotropy is more conspicuous in S-waves. The S-wave in HTI media splits to two waves travelling with different velocities in directions parallel and orthogonal to the fracture orientation. The wave splitting phenomenon is known as 'birefringence' and discussed in Chapter "Shear Wave Seismic, AVO and Vp/Vs Analysis". The direction dependent velocities in intrinsic anisotropic media also result in varying amplitudes with offset or angle of incidence, as evinced in wide-azimuth, far- offset seismic data.

Fluid Properties of Rocks

Pore Fluid and Saturation

Most sedimentary rocks have fluid in pore space. Fluids typically are known to have negligible shear modulus but affect compressional seismic properties depending on its compressibility and density. In a fully water or brine-saturated reservoir rock, water or brine offers resistance to stress and tends to increase velocity though not to the same extent as in a tight rock having little water. Oil saturation in rock pores lowers velocity marginally compared to that with water, as the comparatively lower bulk modulus of oil is offset to some extent by its lower density. However, based on velocity, it is usually hard to distinguish one from the other. In general, rocks saturated fully with liquids exhibit increased seismic properties (Wang 2001). Gas, on the other hand, has the least bulk modulus (highly compressible) and density, and the velocity and impedance of a rock with gas in the pore tend to show significantly lower values than that of rocks saturated with water and/or oil. The lowering of seismic velocity due to presence of gas, even in small quantity, is conspicuously large, especially at shallow depths (Fig. 9). Overall, the effect of fluid-saturation on seismic velocities decreases with increasing depth.

Seismic properties are influenced by both rock matrix and fluid properties and given the reality of wide variations that commonly occur in nature, it may not be always easy to differentiate the effect of one from the other. However, presence of gas in rock pores is more readily detectable as it considerably impacts seismic properties. But to

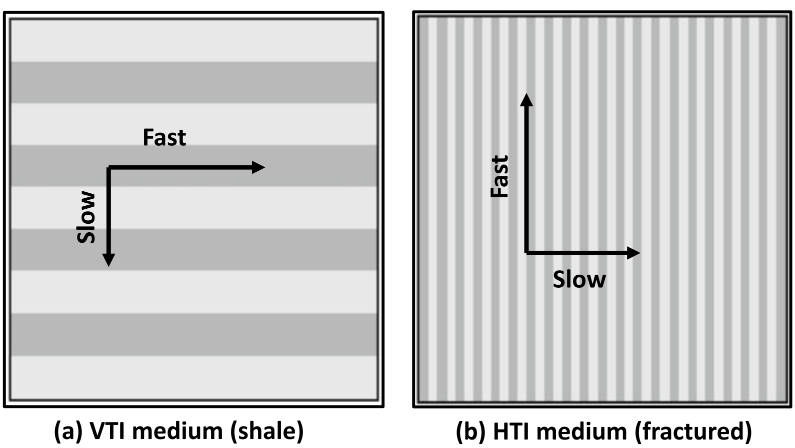

Fig. 8 Schematic diagram illustrating seismic anisotropy in vertical and horizontal transverse isotropic media. Note the direction dependent velocities in VTI and HTI anisotropic media, (**a**) faster velocity along the bedding plane and (**b**) along the fracture orientation (courtesy S. Chopra, Calgary)

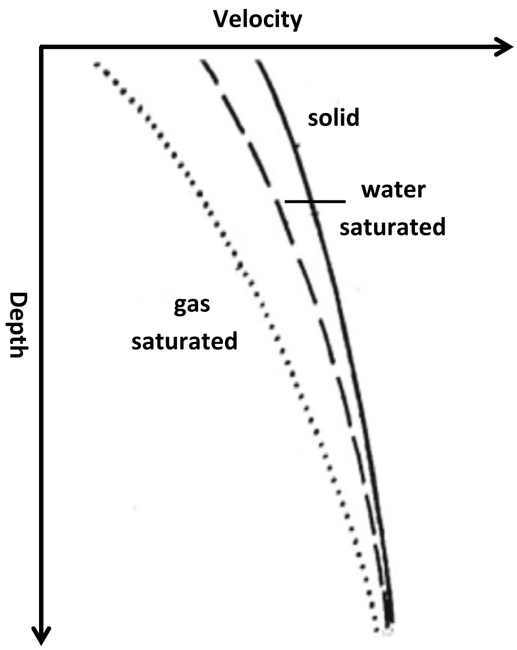

Fig. 9 Variation of velocity with depth for solid, water and gas saturated rocks at normal pressure. Velocity variation is significant at shallow depths but tends to be marginal at greater depths (after Anstey 1977)

estimate partial fluid saturations, that is, the percentage of water, oil and gas in rocks from analysis of seismic properties is difficult. It is interesting to note that though gas in most cases can be easily detected, estimating its saturation is a challenge. This is because as low as 5–10% saturation and 100% gas saturation is known to result in very similar seismic response.

Gassmann's Equations

Nevertheless, several physical and numerical methods have been deployed to model and study impact of fluid saturation on rock velocity. But by far the most widely used relations are the Gassmann's equations to calculate effect of different fluid saturations on seismic properties. It computes the impact of fluid saturation on bulk modulus in porous medium using the known bulk modulii of the other elements of a porous rock – the frame, the matrix, and the pore fluid by modelling (Wang 2001). There are, however, several assumption to Gassmann's equation, including a major one that the porous material is isotropic, elastic, and homogeneous, which is often not the case in many hydrocarbon reservoirs. In fact, most reservoirs are known to be heterogeneous and mildly anisotropic. Particularly, for reservoirs having intricate pore and crack geometry with voids of varying aspect ratios, the Gassmann's equations do not apply well. Kuster and Toksöz (1974) developed a method for such situations where velocities are calculated taking into consideration the impacts due to different aspect ratios of pores. For a given porosity, seismic velocities increase as the pore aspect ratio increases

Permeability

Permeability is the property which denotes the ability of a fluid to flow in a rock. It has no linkage whatsoever with elasticity and density to influence seismic properties. High porosity often estimated may not be the effective porosity which is about the connectivity of the pores. Effective porosity computed from well logs, though is the closest, it is not the actual measure of permeability. Permeability depend on pore throats and tortuosity in a rock and can be measured from cores in laboratories. Unfortunately, permeability, the most important fluid property cannot be predicted from seismic.

Viscosity

Rocks tend to exhibit increasing elasticity and density with increase in viscosity of oil. Heavy oil has large bulk modulus and in some cases may tend to act as semisolids in the rock pores (Wang 2001). These rocks obviously exhibit relatively higher seismic properties.

Pressure

Besides the rock and fluid properties, pressure and temperature at depth also influence seismic response. Ignoring the horizontal tectonic stresses, rock at depth is basically under two vertical stresses, opposing each other. These are the overburden (geostatic or lithostatic) pressure, also known as the confining pressure and the fluid pressure or pore pressure (formation pressure). Overburden pressure at a depth is the pressure exerted by the overlying rocks acting downwards due to gravity while the pore pressure of fluid in the rock pores acts upwards due to buoyancy of fluid. While the overburden pressure tends to close the pores, the opposing pore pressure tries to retain the voids. The difference between these two pressures, is known as the effective pressure or differential pressure and is an important factor in influencing seismic properties. Change in effective pressure impacting closing or opening of pores and cracks, results in increase or decrease of elastic moduli of the rock. Higher effective pressure increases seismic properties and vice versa.

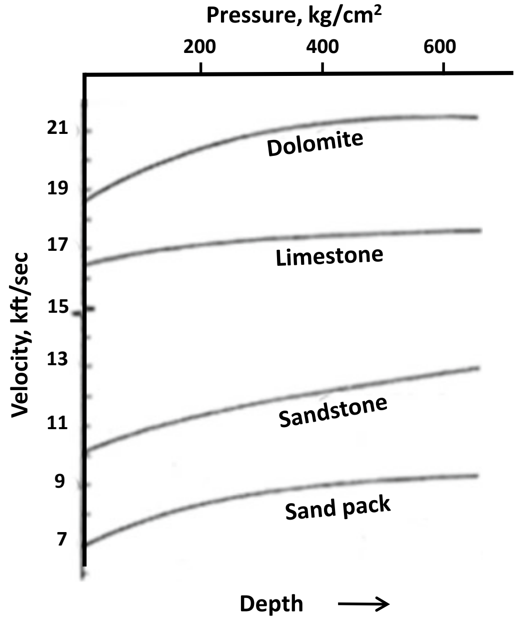

Fig. 10 Impact of pressure on seismic velocity for different rocks. P-velocity increases with increasing effective pressure, variation more conspicuous for rocks at shallow depths in lower pressure regimes (modified after Gregory 1977)

Normal Pressures (Hydrostatic Pressure)

As deposition continues, sediments get buried in depth and starts getting compacted under loading by expelling water. In properly compacted sections where the expelled water escapes to the surface, it maintains hydraulic communication with it and the formation shows hydrostatic pressure, commonly termed the normal pressure. Hydrostatic pressure, typically has a gradient of 0.43psi/ft; the pressure gradient defined as the rate of change in formation fluid pressure with depth. Hydrostatic pressure, however, is controlled by the density of the fluid saturating the formation. Fluid density in formation changes with depth due to temperature and pressure and also with the type of fluid. Consequently, brine saturated rocks show higher hydrostatic pressure gradient than the oil and gas saturated rocks exhibiting lower gradients.

In normally-pressured sections, effective pressure increases with depth because of increasing overburden pressure and raises elasticity and density of the rock resulting in higher seismic properties. The increase in velocity, however, is nonlinear with depth and is more pronounced at shallower depths and in lower ranges of effective pressure (Fig. 10). The degree of change, however, varies with lithology, depending on elasticity of the rock (hardness), being maximum in soft unconsolidated sands and minimum in limestones.

Abnormal Pressures

Abnormal pressures are often labeled improperly as overpressures. Abnormal pressure is what is not normal and it can be higher or lower than normal pressures. Pressures higher than normal hydrostatic pressure are known as overpressured and lower as underpressured or subnormal-pressured.

Overpressures

Overpressures are generated by several mechanisms, the more common being the compaction or '*loading*' and fluid volume expansion or '*unloading*'. In some geologic settings, formations undergoing subsidence release pore water under compaction, which, however, cannot escape to surface because of impermeable rocks at its top acting as seal, rocks such as shale or tight limestones. The expelled water thereby is forced to stay within the formation resulting in raising the pore pressure. This can happen in areas where rapid subsidence with huge amount of sediment loading occurs. If the rapid loading of sediments increases the overburden pressure at a rate which the escape of released fluid cannot keep pace with, the pore fluid has to support a large part of the load and thereby increasing the fluid pressure. The formation without going through normal compaction, remains undercompacted and exhibits fluid pressure higher than normal hydrostatic pressure and the formation is termed over-pressured (Fig. 11).

Overpressures due to the fluid volume expansion mechanism is known as '*unloading*'. This usually occurs in low permeability rocks such as shale, where fluid changes phase mainly due to generation of hydrocarbon during thermal cracking of organic matter, described later in Chapter "Seismic stratigraphy and Seismo-tectonics in Petroleum Exploration". Overpressures may also happen due to clay diagenesis and other causes such as by tectonics and geothermal heating where increased volume of fluid, constrained by the limited rock matrix exerts higher fluid pressure (Fig. 12). The over-pressured rocks compared to a normally pressured layer, at the same depth characteristically show lower effective pressure, higher pore pressure, decreased elasticity, interval velocity and bulk density. The decreased trends of density and velocity typically tend to remain constant in the high-pressured zone despite increasing depth of burial (Figs. 13 and 14). Continued thickening of the overburden in such cases does not affect the seismic velocity in the zone as the high pore-fluid pressure continues to withstand the increasing part of the overburden pressure with depth. Overpressures and pore pressures can be detected from sonic and density logs by their characteristic anomalous features of density remaining

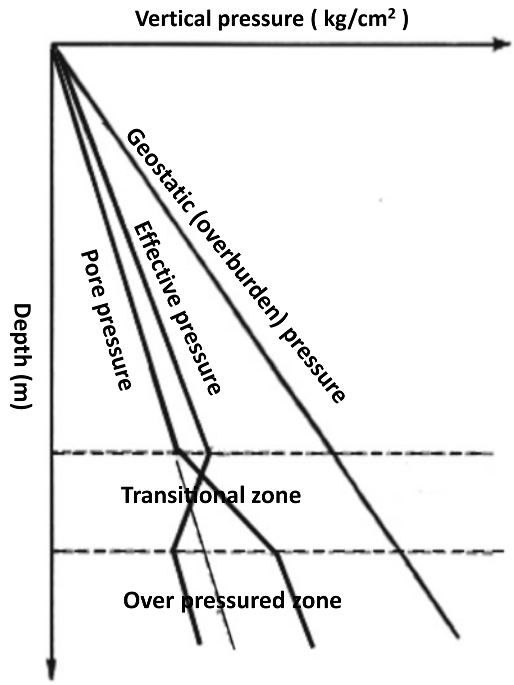

Fig. 11 Schematic showing geostatic, hydrostatic (normal) and effective pressure (difference between geostatic and pore pressure). In under-compacted rocks, the unexpelled water remaining in pores cause higher pore pressure than hydrostatic and are known as over-pressured rocks. Over-pressured formations show reduced effective pressure

constant and velocity reversing trend with depth despite increasing depth (Fig. 15). Overpressures can also be indicated from seismic velocity, discussed in Chapter "Evaluation of High-Resolution 3D and 4D Seismic Data".

Underpressures or Subnormal Pressures

The causes of subnormally low pressured formations are not clearly understood. However, when a saturated porous formation is subjected to uplift and erosion, the overburden pressure is reduced causing a partial elastic rebound of the reservoir matrix which was previously under compaction. The increase in volume of the pores eases pore pressure to reduce pressure and the formation exhibits subnormal pressures. Compaction in shales due to increase in depth is inelastic in