
PRINCIPLES AND APPLICATIONS OF SEISMIC REFLECTION GEOPHYSICAL TECHNIQUE IN PETROLEUM EXPLORATION AND PRODUCTION: A REVIEW

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Abstract

This paper investigates the role of seismic reflection techniques in petroleum exploration and production, focusing on advancements in 2D and 3D seismic technologies, inversion methods, and data processing techniques such as pre-stack depth migration (PSDM) and full-waveform inversion (FWI). The integration of seismic data with well information has significantly improved the characterization of reservoirs, enhancing decision-making in the placement of wells and management of production. Case histories, such as those from Nigeria's Integration of Seismic and Well Log Data for Reservoir Characterization in Offshore Niger Delta, Nigeria and Agbami fields, demonstrate how these advanced seismic techniques optimize hydrocarbon recovery, reduce production risks, and refine exploration success. Furthermore, the future of seismic techniques in resource exploration is discussed with attention to their roles in sustainability, cost efficiency, and the energy transition.

Keywords: Seismic Reflection, Reservoir, Petroleum, Exploration, Production, Niger Delta, Agbami field.

1.0 Introduction

1.1 Overview

Reflection seismology (or seismic reflection) is a method of exploration geophysics that uses the principles of seismology to estimate the properties of the Earth's subsurface from reflected seismic waves.

Of all the geophysical exploration methods, seismic surveying is unequivocally the most important, primarily because it is capable of detecting large-scale to small-scale subsurface features. Simply stated, seismic methods involve the estimation of the shapes and physical properties of Earth's subsurface layers from the returns of sound waves that are propagated through the Earth (Mondol & Bjorlykke, 2010). Early wildcatters found oil by drilling natural oil seeps and large folds (anticlines) in exposed rocks. These easy oil prospects were all quickly discovered and drilled, and geologists then turned to seismic surveys to find less obvious oil and gas traps. Seismic technology has been used since the early 1900s to measure water depths and detect icebergs, and by 1924, seismic data were first used in the discovery of a Texan oil field (Milligan 2004). In general, two seismic methods are common: Refraction and Reflection. But this paper will explain all about seismic reflection.

Seismic reflection is the most widely used geophysical technique. It can be used to derive important details about the geometry of structures and their physical properties. This technique provides an image of the subsurface in two or three dimensions (2D or 3D) (Fig. 17.1). The subsurface seismic images are produced by generating, recording, and analyzing sound waves that travel through the Earth (such waves are also called seismic waves). The density and velocity changes between rocks reflect the waves to the surface, and how quickly and strongly the waves are reflected back indicates what lies below (Mondol & Bjorlykke, 2010).

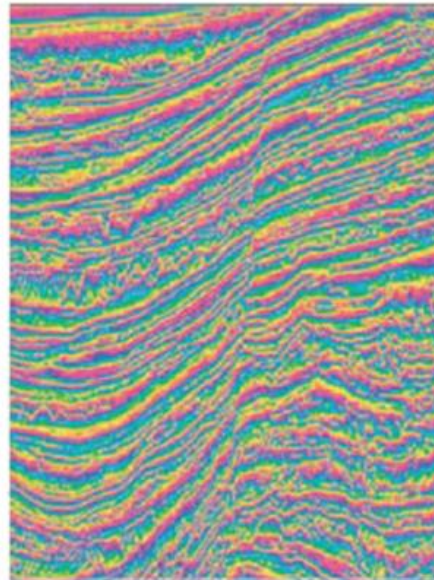


Fig 1. Subsurface imaging by 2D
Source: (Hübscher & Gohl, 2014).

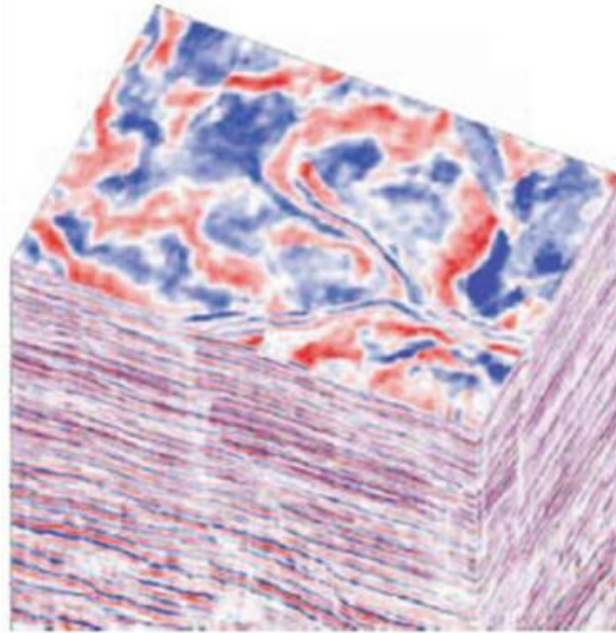


Fig 2. Subsurface imaging by 3D
Source: (Hübscher & Gohl, 2014).

1.2 History of seismic reflection

Seismic reflection exploration grew out of the seismic refraction exploration method, which was used to find oil associated with salt domes (Elford, 1976). Ludger Mintrop, a German mine surveyor, devised a mechanical seismograph in 1914 that he successfully used to detect salt domes in Germany. He applied for a German patent in 1919 that was issued in 1926 (“Seismic Reflection” 2023).

Marine reflection seismology evolved from work by Reginald Fessenden who developed a sonic sounder to find icebergs (after the sinking of the Titanic) (Roden, 2005). The first reported usage of seismic reflections for subsurface studies was in 1921 when a small team of geophysicists and geologists performed a historical experiment in Oklahoma (Dragoset, 2005). The team analyzed the return time of reflected waves generated by small dynamite charges and detected the boundary between two subsurface geological layers. The success of this so-called Vines Branch experiment stimulated a boom in seismic exploration when the oil price rose in 1929. During the first decades, each subsurface point was imaged by a single set of sources and receivers. Multichannel seismics became more common in the 1950s. This method allowed for significant noise reduction and computing of layer velocities, enabling the conversion of travel times to depth. The advent of digital technology in the 1960s represented a giant step forward because digital post-processing opened a wide variety of possibilities to enhance seismic data and image quality. Several technical developments in the 1980s such as plotters for wiggle trace display or color maps as well as methodical progress including seismic stratigraphy or seismic attribute analysis became available for earth scientists and stimulated academic frontier research. The hydrocarbon industry benefited largely from the introduction of the 3D seismic method which enhanced understanding of petroleum reservoirs and reduced exploration risks. However, the earth science community has had quite limited access to these data, also because 3D seismic experiments for nonprofit-oriented research are generally too costly (Hübscher & Gohl, 2014).

Typical applications of seismic reflection include:

- i. Oil and gas exploration;
- ii. Geological mapping studies;
- iii. Mineral exploration;
- iv. Civil engineering site investigations.

1.3 Basic Principles

The first step in seismic exploration is to acquire data, which in most cases is carried out from the surface. To understand the seismic data, a review of the physical principles that govern the movement of seismic waves through layered media is necessary (Hübscher & Gohl, 2014). The basic principle of the seismic reflection technique application is to measure the time taken for a seismic wave that travels from a source down into the ground where it is reflected to the surface where it can be detected by a receiver (geophone). A seismic source at any point on the Earth generates four types of seismic waves: compressional (P-wave), shear (S-wave), Rayleigh (ground roll), and Love, that travel through the layers (Fig. 17.2). Each layer will have a specific density and velocity. Rayleigh and Love waves are surface waves and propagate approximately parallel to the Earth's surface. Although surface waves penetrate to significant depths in the Earth, these types of waves do not propagate directly through the Earth's interior and have limited significance in oil and gas exploration. On the other hand, P- and S-waves are often called body waves because they propagate outward in all directions from the source travel through the interior of the Earth, and have great significance in seismic exploration. P-waves move faster than S-waves. The P-wave is a longitudinal wave, the force applied in the direction that the P-wave is traveling. The ground must move in that direction. The ground or Earth is incompressible, so the energy is transferred pretty quickly. In the S-wave, the medium is displaced in a transverse way (up and down compared to the line of travel), and the medium must move away from the material right next to it to cause the shear and transmit the wave. This takes more time, which is why the S-wave moves more slowly than the P-wave in seismic events. S-waves do not travel through fluids as fluid has no shearing capacity (Hubscher & Gohl, 2014).

The measured time is known as the two-way time (TWT). The basic issue in seismic reflection interpretation is the conversion of the measured two-way time into depth. Although the two-way time (TWT) is known (measured), still there are two unknown parameters; these are depth and velocity. Velocity is considered as the parameter that most affects the conversion of the two-way time into depth.

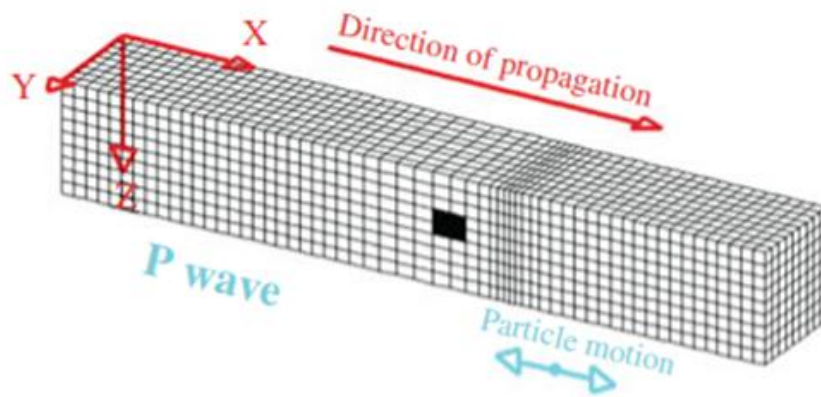


Fig 3 Propagation of P waves as a function of particle motion
Source: (Hübscher & Gohl, 2014).

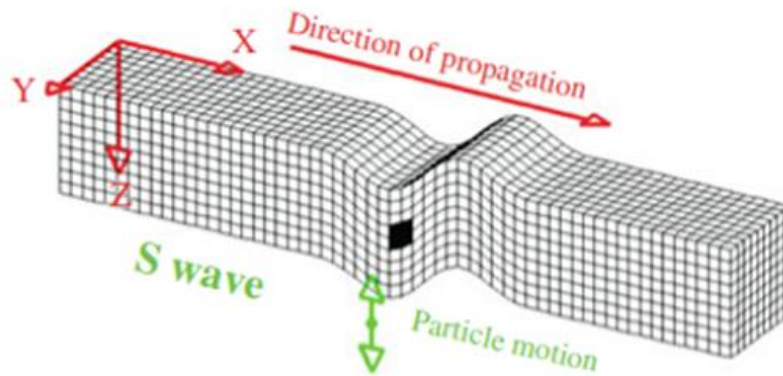


Fig 4 Propagation of S waves as a function of particle motion
Source: (Hübscher & Gohl, 2014).

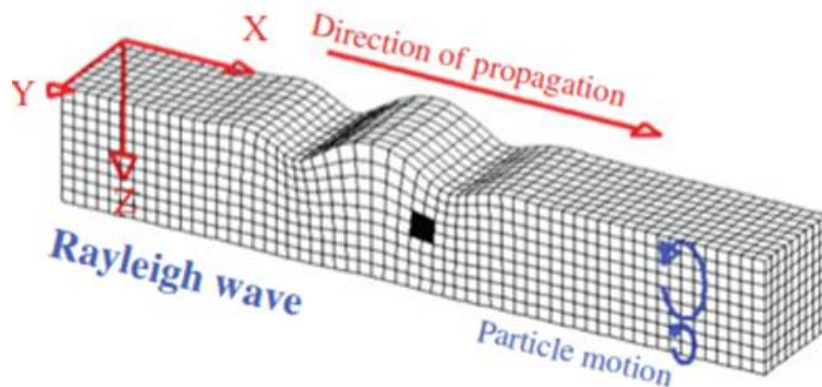


Fig 5 Propagation of Rayleigh waves as a function of particle motion
Source: (Hübscher & Gohl, 2014).

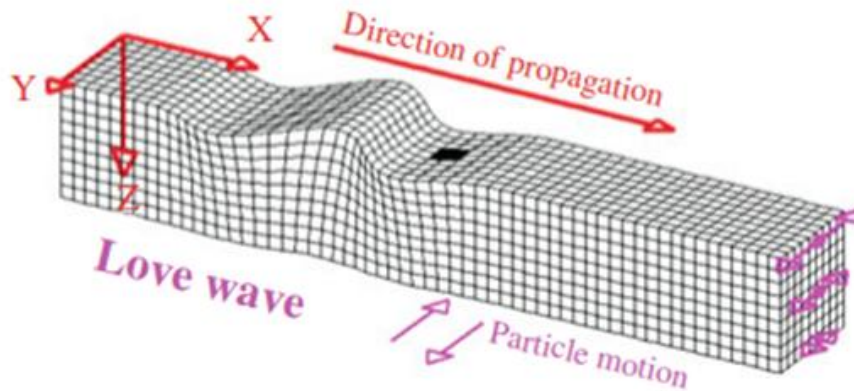


Fig 6 Propagation of Love waves as a function of particle motion
 Source: (Hübscher & Gohl, 2014).

Travel in the Earth at a speed governed by the acoustic impedance of the medium in which they are traveling. The acoustic (or seismic) impedance, Z , is defined by the equation:

$$Z = \rho v, Z = v\rho$$

where v is the seismic wave velocity and ρ (Greek *rho*) is the density of the rock.

When a seismic wave traveling through the Earth encounters an interface between two materials with different acoustic impedances, some of the wave energy will reflect off the interface and some will refract through the interface. At its most basic, the seismic reflection technique consists of generating seismic waves and measuring the time taken for the waves to travel from the source, reflect off an interface, and be detected by an array of receivers (such as geophones or hydrophones) at the surface (Sheriff & Geldart, 1995).

If the two layers have different velocities, they will as a rule also have different densities, and part of the acoustic energy will not be refracted but reflected. How much of the energy is reflected depends on the difference in the impedance [P-impedance (Z_p) or S-impedance (Z_s)], which are the product of P-wave (V_p) or S-wave (V_s) velocities and density (ρ). The reflection coefficient (R) of a normally incident P-wave on a boundary is given by:

$$RC = \frac{p_2 v_2 - p_1 v_1}{p_2 v_2 + p_1 v_1} \quad 1.1$$

where p_1 and p_2 are the densities of the upper and lower layers, V_1 and V_2 are their respective P-wave velocities, and $p_1 V_1$ and $p_2 V_2$ are the P-impedances of the upper and lower layers respectively. Therefore, anything that causes a large contrast in impedance in the target zone can cause a strong reflection (Fig. 17.4). The possible candidates include:

- i. changes in lithology
- ii. Porosity
- iii. Pore fluid
- iv. Degree of saturation and
- v. Diagenesis.

We see that the greater the difference in density and velocity of the two layers, the greater the amount of energy that will be reflected. Sandstone will often have significantly different acoustic impedance from shale and a considerable amount of sound energy will be reflected from the boundary between a sandstone bed and a shale bed. Limestones will tend to have both high velocities and high densities. The result will be an even greater contrast in acoustic impedance between limestones and, for example, shales. However, this contrast will always depend on the porosity of the limestone, though even rather porous limestones have relatively high velocities because they are usually well-cemented (Hübscher & Gohl, 2014).

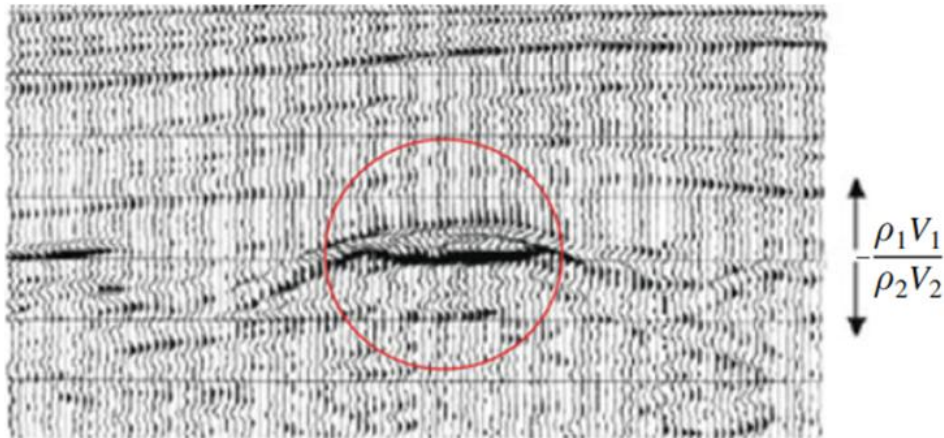


Fig 7 A seismic section showing a large impedance contrast within the target zone (marked by a red circle)

Source: (Hübscher & Gohl, 2014).

2.0 Equipment for Seismic Reflection Survey

2.1 Seismic Reflection Sources

A seismic source is defined as any device that releases energy into the earth in the form of seismic waves (Sheriff, 1995). There are two main groups of seismic sources: land seismic sources and marine seismic sources.

In marine seismic surveys, the sources are subdivided into exploders and imploders. Exploders create the wavelet by an expanding volume (solid material or gas/air). Imploders generate the signal by the collapse of a volume, created for instance by cavitation. We can further distinguish between chemical, mechanical, electrical, and pneumatic/hydraulic sources (Parkes and Hatton, 1986). Chemical sources comprise various explosives. Explosives can create very strong signals; however, the shot interval is relatively low, and the signal characteristics are reproducible to a limited amount due to surface waves and explosion depth. Mechanical sources, such as a boomer or piezoelectric transducers, rely on physical vibration to transmit seismic waves into the water. Sparkers are electrical sources that discharge large electrical charges into the water. The steam bubble that vaporizes along the spark collapses, thus producing the desired signal. Pneumatic/hydraulic sources dispel gas (usually air) or fluid (usually water) under high pressure into the water. For instance, a water-ejecting water gun produces a cavitation, and its subsequent collapse generates a seismic wave-field. The water is accelerated in the water gun by a piston, whereas the driving pressure consists usually of compressed air. The pneumatic so-called air gun is nowadays the most common source in marine seismic (Dragoset, 1990). Compressed air of usually 140–210

bar is released into the water every few seconds. The rapid expansion creates the highly reproducible primary signal (Fig. 3.1a). The reflection at the sea surface creates a similar strong but phase-reversed signal, the so-called ghost. Signal strength is described either as the peak amplitude pk (level A in Fig. 3.1a) or as pk amplitude which includes the amplitude of the ghost arrival (A–B in Fig. 3.1a), both traditionally expressed in bar-meter (bar-m). If the peak amplitude is 1.5 bar-m as in Fig. 3.1a, a hydrophone located at a distance of 1 m to the source would measure a peak amplitude of 1.5 bar, in a 3m distance of 0.5 bar. A second important source characteristic is the spectral bandwidth (Fig. 3.1b). Amplitude spectra are usually shown on a logarithmic scale. A reasonable parameter for the bandwidth is the range between the 3db (71 % of maximum) or 6db (50 % of maximum) points.

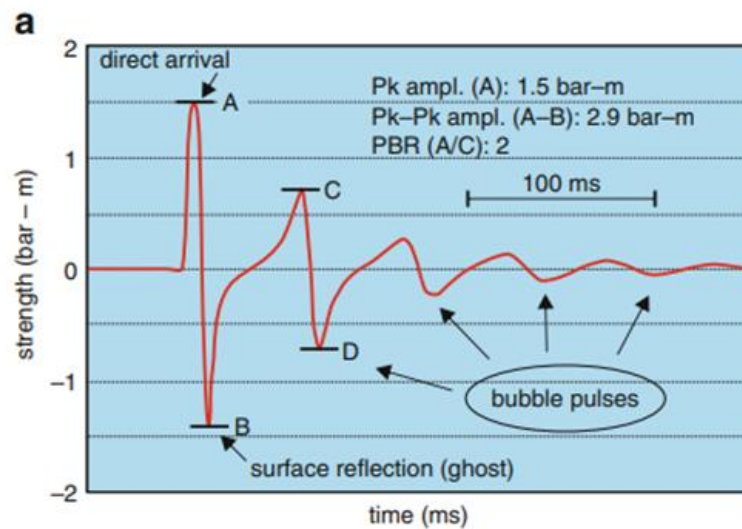
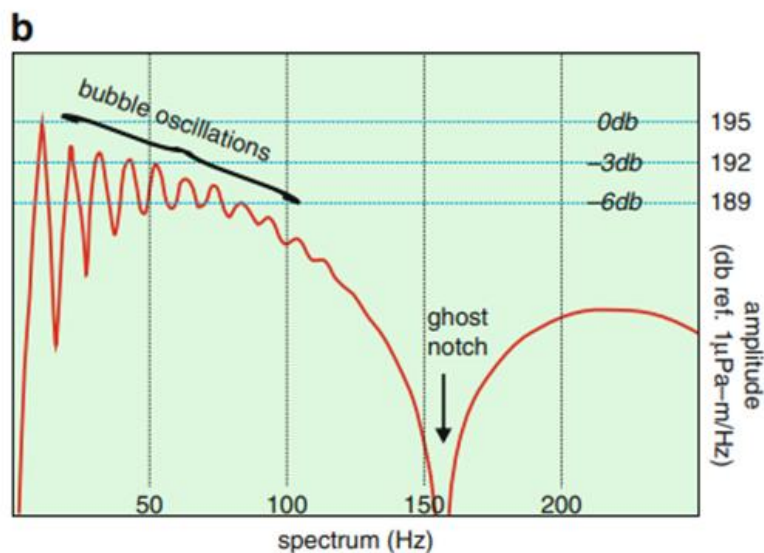


Fig 8(a) Definitions of time-domain air gun specifications (Source: Dragoset, 2005).



(b) The spectral bandwidth is usually shown on a logarithmic scale (Source: Dragoset, 2005).

Land Seismic acquisition sources include:

- i. Sledgehammers,

- ii. Explosives,
- iii. Vibroseis, and
- iv. Thumper trucks.

The most basic seismic source is a sledgehammer. A seismic energy is generated either by striking the ground directly or more commonly striking a metal or polyethylene plate on the ground. Typically applied for near surface seismic refraction surveys. The impact of sledgehammer contact with the surface can provide sufficient seismic energy for interface depths up to 30 m or more, depending on geological conditions and physical properties (Reynolds, 2011).

Explosives most widely used as seismic sources are known as gelatin dynamites. These dynamite are placed into three subcategories, straight gelatins in which nitroglycerin, also known as glyceryl trinitrate with the chemical formula $C_3H_5(ONO_2)_3$ is the active component, ammonia gelatins in which ammonia nitrite with chemical formula NH_4NO_3 as the active component, and semi gelatins in which the composition consists mostly of nitroglycerin (Andreas, 2010). Upon detonation, explosives release large volumes of expanding gas very quickly (Encyclopedia Britannica, n.d.) forcing great pressure on the surroundings in the form of seismic waves.

Using explosives as seismic sources has been in practice for decades because of the reliability and energy efficiency they provide (Yordkayhun et al, 2009). Such sources are most commonly used on land and swampy environments because of the high thickness of sediments. Typical charge sizes used in the field for reflection surveys are 0.25 kg to 100 kg for single-hole sources, 0.25 kg to 250 kg or more for multiple-hole sources and may reach 2500 kg or more for refraction surveys (Stark, 2010). Though dynamites and other explosives are efficient seismic sources because of their reduced costs, ease of transport in difficult terrains, and lack of regular maintenance compared to other sources (Strobbia et al, 2009) the use of explosives is becoming restricted in certain areas, causing the decline and increasing popularity for alternative seismic sources (Yordkayhun et al, 2009). Dynamite can generate usable signal strengths and a bandwidth that covers a wide spectrum of seismic energy (Mondol & Bjørlykke, 2010).

2.2 Seismic Reflection Receivers

Hydrophones and geophones serve as receivers for seismic signals. The hydrophone is a device designed for use in detecting seismic energy in the form of pressure changes in water during marine seismic acquisition. It measures pressure variations with the aid of piezoelectric material, which generates a voltage upon deformation. The two piezoelectric elements in one hydrophone are connected and polarised so that voltages due to pressure waves (returning signal) add and voltages due to one-directional acceleration will cancel. In this way, the influence of movements due to currents, wave action, and so on will be minimized. Hydrophones are combined to form streamers that are towed by seismic vessels or deployed in a borehole. A typical length of a streamer is about 4–6 km where a single receiver section is typically 75 m long and contains 96 hydrophones which are grouped in arrays of a pre-defined length, mostly 12.5 or 25 m (Mondol & Bjørlykke, 2010).

Usually, groups of hydrophones are used to eliminate translational accelerations and to enlarge the signal-to-noise ratio by signal summation (Telford et al., 1990).

The geophone is a device used in surface seismic acquisition, both onshore and on the seabed offshore, that detects ground velocity produced by seismic waves and transforms the motion into electrical impulses. Geophones, unlike hydrophones, detect motion rather than pressure. Conventional seismic surveys on land use one geophone or a group of geophones per receiver location to detect motion in the vertical direction. The three-component (3C) geophone is used for direct measurements of shear waves at the seafloor. An essential feature of a seafloor seismic acquisition is the four-component (4C) detector unit, which includes a hydrophone and a three-component (3C) geophone. The hydrophone and the vertical geophone measure pressure waves, whereas the two extra horizontal geophones measure particle velocity associated with shear wave energy (Mondol & Bjørlykke, 2010).



Fig 9 Hydrophone

Source: (Mondol & Bjørlykke, 2010).

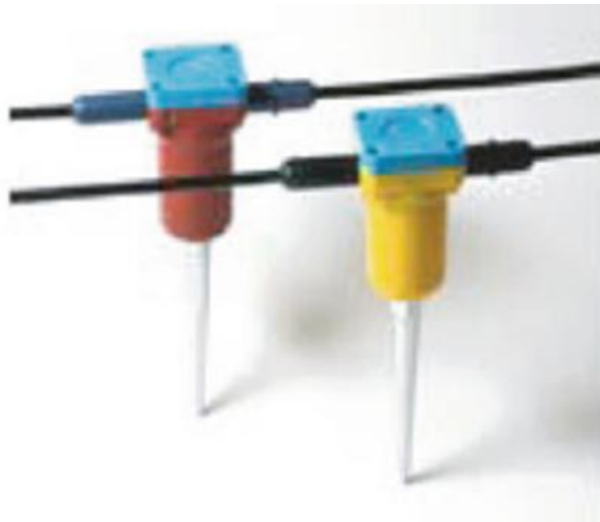


Fig 10 Geophone

Source: (Mondol & Bjørlykke, 2010).

3.0 Data Acquisition and processing

3.1 Overview

Survey design and planning in seismic data acquisition is a complex process that requires careful consideration of numerous factors. The primary goal is to optimize the illumination of subsurface targets while minimizing costs and environmental impact. One crucial aspect is the determination of source and receiver geometries. For land surveys, this often involves designing orthogonal or slanted orthogonal grids, with source line spacing typically ranging from 200 to 800 meters and receiver line spacing from 200 to 400 meters, depending on the target depth and desired resolution (Cordsen et al., 2000). In marine surveys, streamer configurations must be optimized, with modern surveys often employing wide-azimuth (WAZ) or multi-azimuth (MAZ) designs to improve subsalt imaging (Long et al., 2006).

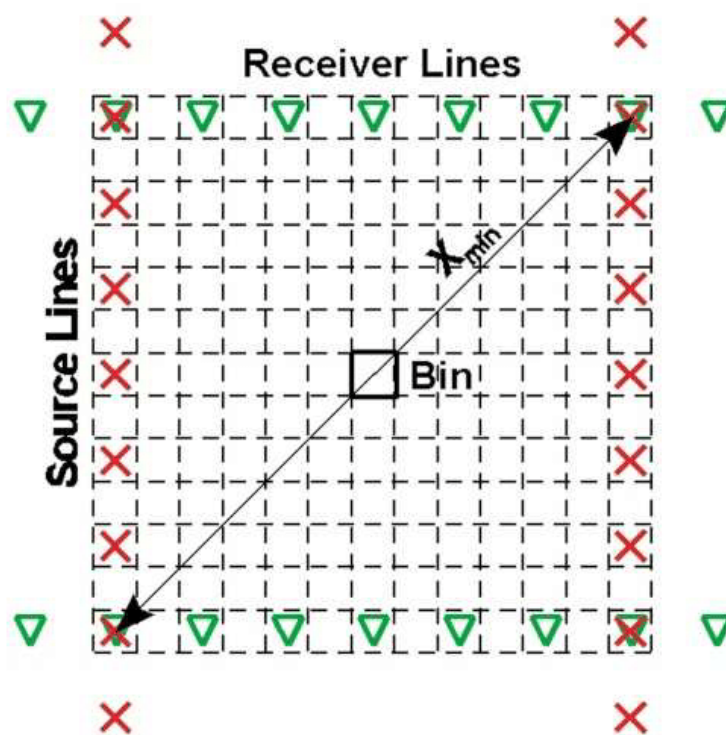


Fig. 11. A sample source and receiver geometry with definition of bin and X_{min} . The red crosses are shot points and the green triangle receiver stations (Cordsen et al., 2000).

The selection of appropriate source and receiver parameters is equally critical. Source frequency content must be tailored to the depth of investigation, with deeper targets requiring lower frequencies (typically 5-80 Hz) and shallower targets allowing for higher frequencies (up to 250 Hz in some cases) (Lansley, 2004). Geophone natural frequencies are chosen based on the expected signal bandwidth, typically ranging from 10 Hz for deep targets to 40 Hz for shallow high-resolution surveys. The vertical and lateral resolution of the survey is directly related to these frequency choices, following the quarter-wavelength criterion (Yilmaz, 2001).

Advanced modeling techniques play a crucial role in survey design. Ray tracing methods, such as those implemented in software like OMNI 3D, are used to predict coverage and

identify potential shadow zones (Gjøystdal et al., 2002). Full-wave simulation techniques, including finite-difference and spectral element methods, provide more accurate predictions of wave propagation in complex geological settings, allowing for better optimization of acquisition parameters (Robertsson et al., 2007). These simulations can also help in predicting and mitigating the effects of noise sources, such as ground roll in land surveys or multiples in marine environments.

3.2 Field Operations: Data Acquisition

Field operations in seismic data acquisition have seen significant technological advancements in recent years. In land surveys, the transition from cabled systems to wireless nodal receivers has revolutionized data collection in challenging terrains. Modern nodal systems, such as the Sercel UNITE or Wireless Seismic RT2, can operate autonomously for weeks, recording continuously at high sample rates (typically 2 ms) and with a dynamic range exceeding 130 dB (Dean et al., 2013). This technology has enabled the implementation of high-density surveys, with receiver spacing as close as 5-10 meters in some cases, greatly improving near-surface resolution.

Source technology has also evolved, particularly in vibroseis operations. Modern vibrator trucks can generate sweeps with frequencies up to 250 Hz and employ advanced techniques such as slip-sweep acquisition to increase productivity (Meunier, 2011). In areas where explosive sources are required, the use of automated drilling rigs and electronic detonators has improved efficiency and safety. Marine operations have seen the development of advanced source and streamer steering systems, allowing for more precise control of source and receiver positions in the presence of currents and obstacles (Tabti et al., 2009).

Quality control during acquisition has become increasingly sophisticated, with real-time monitoring systems capable of analyzing vast amounts of data in the field. Key quality indicators include signal-to-noise ratios, spectral content, and trace-to-trace correlation, all of which are monitored in real-time to ensure data quality meets predefined standards (Crice, 2014). Advanced noise detection algorithms can identify and flag problematic traces, allowing for rapid troubleshooting and equipment replacement if necessary.

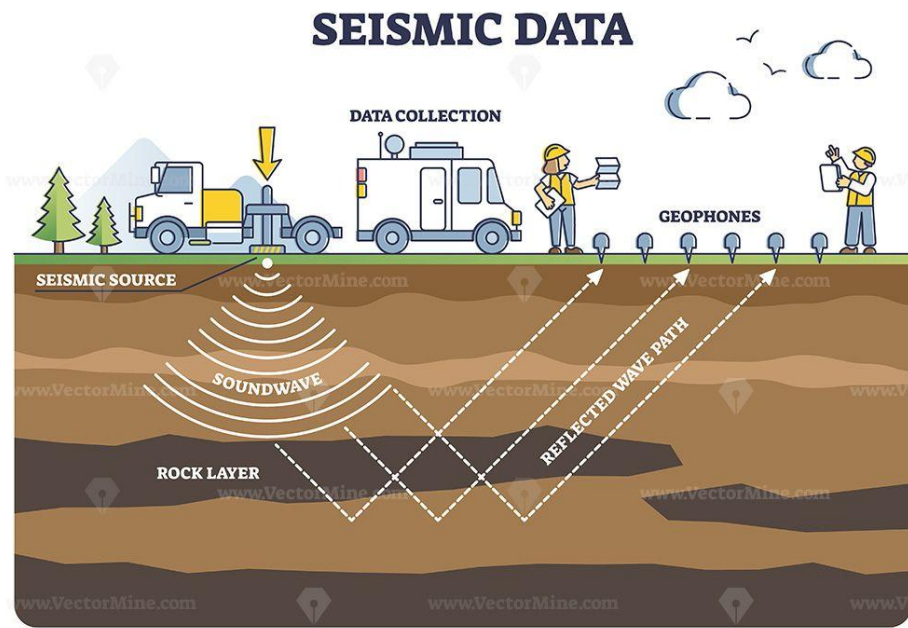


Fig. 12. Seismic data collection method with geophones and soundwave outline (Source: pinterest)

3.3 Data processing

3.3.1 Pre-stack and Post-stack processing

Pre-stack processing has become increasingly important as the industry moves towards preserving and utilizing the full wavefield for imaging and characterization. Noise attenuation techniques have advanced significantly, with methods such as curvelet-domain filtering and time-frequency de-noising proving effective in preserving signal while removing both coherent and random noise (Naghizadeh and Sacchi, 2012). Surface-related multiple elimination (SRME) has become a standard technique in marine processing, with 3D SRME now commonly applied to wide-azimuth datasets (van Borselen et al., 2013).

Velocity model building, a critical component of pre-stack processing, has seen significant advancements. Tomographic methods, including both ray-based and wave-equation tomography, are now routinely used to derive high-resolution velocity models (Jones, 2010). These models are crucial for subsequent imaging steps, particularly in areas with complex geology. Pre-stack time migration (PSTM) remains a workhorse of the industry, but pre-stack depth migration (PSDM) is increasingly common, especially in areas with significant lateral velocity variations (Biondi, 2006).

Post-stack processing, while less emphasized in modern workflows, still plays a role in enhancing final image quality. Advanced post-stack noise reduction techniques, such as f-x deconvolution and structure-oriented filtering, can significantly improve the signal-to-noise ratio of stacked sections (Abma and Claerbout, 1995). Spectral balancing and Q compensation are often applied to enhance frequency content and improve resolution, particularly for deeper targets (Wang, 2008).

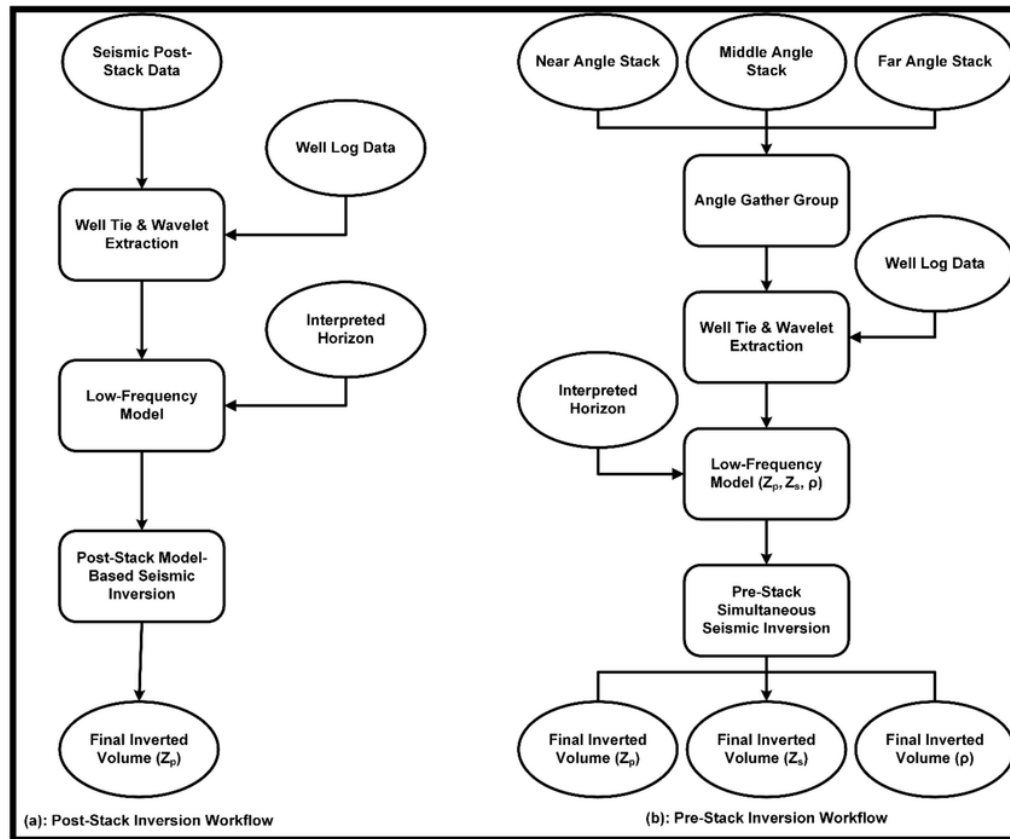


Fig. 13. Workflow of seismic inversion, (a) post-stack seismic inversion, (b) Pre-stack seismic inversion (Urooj *et al* 2022)

3.3.2 Migration and imaging

Migration and imaging techniques have seen perhaps the most significant advancements in recent years. Reverse time migration (RTM) has become the gold standard for imaging in complex geological settings, capable of accurately handling wave propagation in areas with steep dips, strong velocity contrasts, and complex multiples (Baysal *et al.*, 1983). Implementation of RTM on high-performance computing platforms, including GPUs, has made it feasible for routine production use (Abdelkhalek *et al.*, 2009).

Full-waveform inversion (FWI) has emerged as a powerful tool for deriving high-resolution velocity models directly from the seismic data. Modern FWI implementations can incorporate both refracted and reflected energy, allowing for improved imaging of both the near surface and deeper targets (Virieux and Operto, 2009). Multi-parameter FWI, which inverts for additional properties such as density and anisotropy parameters, is an active area of research and development (Operto *et al.*, 2013).

Least-squares migration (LSM) techniques have gained popularity for their ability to improve amplitude fidelity and resolution in the final image. By posing migration as an inverse problem, LSM can compensate for irregular illumination and improve the resolution of the final image (Nemeth *et al.*, 1999). Recent developments in LSM include extensions to anisotropic media and the incorporation of FWI-derived models (Zhang *et al.*, 2015).

Image-domain wavefield tomography, also known as reflection full-waveform inversion (RFWI), has emerged as a promising technique for refining velocity models in areas where traditional FWI struggles. By working in the image domain, RFWI can mitigate cycle-skipping issues and provide improved updates to deeper portions of the velocity model (Sava and Biondi, 2004).

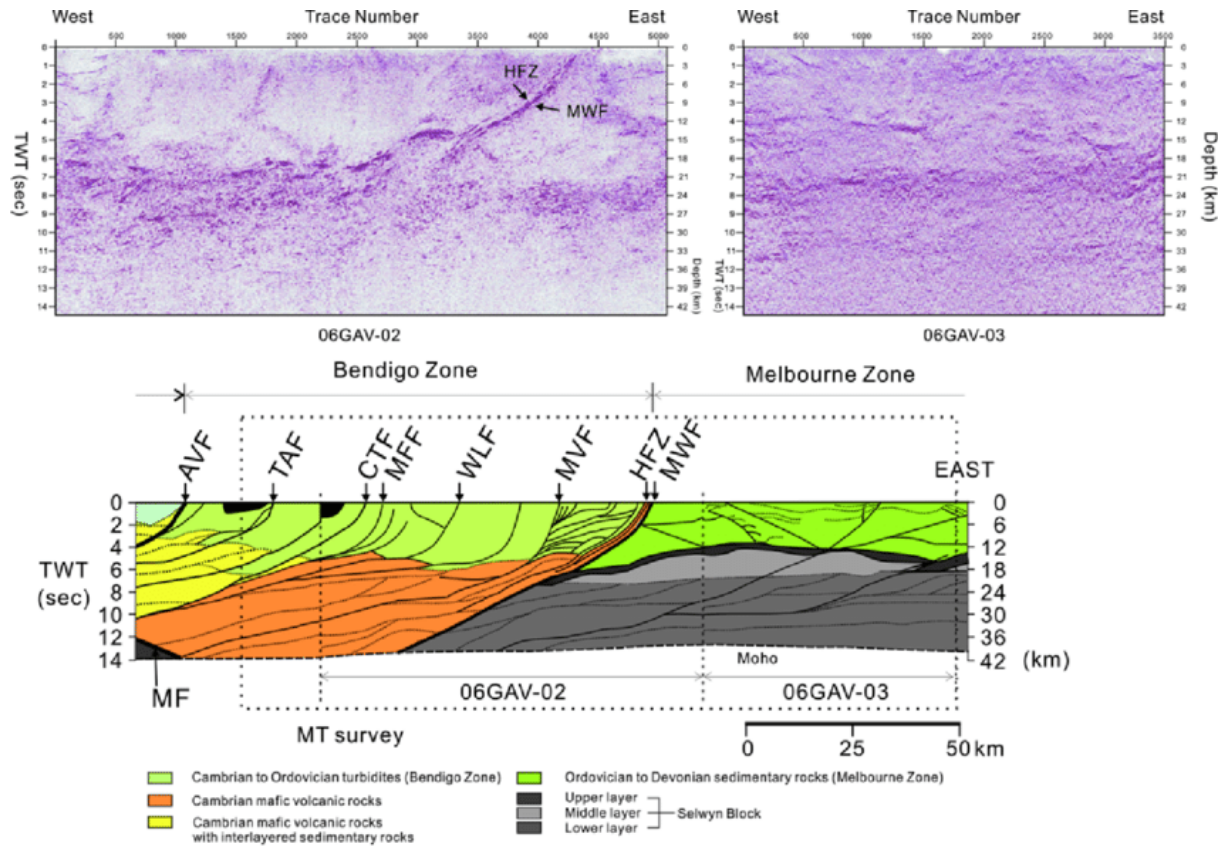


Fig. 14. Seismic migrated section and its interpretation redrawn (Cayley et al., 2011)

3.4 Interpretation of Seismic Data

Seismic data interpretation is a crucial step in the exploration and production of hydrocarbons, as well as in understanding subsurface geology for various other applications. It involves the analysis of seismic data to create a geological model of the subsurface, identifying potential hydrocarbon accumulations, and assessing the risks associated with exploration and production activities (Brown, 2011).

3.4.1 Structural Interpretation

Structural interpretation focuses on identifying and mapping geological structures such as folds, faults, and unconformities within seismic data. This process is fundamental to understanding the tectonic history of an area and identifying potential traps for hydrocarbons.

The first step in structural interpretation typically involves horizon picking, where key reflectors representing geological boundaries are traced across the seismic volume. Modern interpretation software allows for both manual and semi-automated horizon picking, with

algorithms such as neural networks and machine learning increasingly being employed to assist in this process (Chopra and Marfurt, 2019).

Fault interpretation is another critical aspect of structural interpretation. Faults can be identified in seismic data through discontinuities in reflectors, changes in reflector dip, and diffractions. Advanced techniques for fault detection and mapping include coherence analysis, curvature attributes, and ant tracking algorithms (Chopra and Marfurt, 2007).

Three-dimensional visualization tools have revolutionized structural interpretation, allowing geoscientists to view and manipulate seismic data in ways that were not possible with traditional 2D methods. Techniques such as volume rendering and opacity control enable interpreters to see through the data and identify subtle structural features (Bacon et al., 2003).

Time-to-depth conversion is a critical step in structural interpretation, as seismic data is typically acquired and processed in the time domain, but geological interpretations need to be in depth. This process requires accurate velocity models, which can be derived from well data, seismic velocities, and advanced techniques such as full-waveform inversion (Etris et al., 2001).

3.4.2 Stratigraphic Interpretation

Stratigraphic interpretation focuses on identifying and characterizing depositional systems, sedimentary facies, and sequence stratigraphy within seismic data. This type of interpretation is crucial for understanding reservoir distribution and quality.

Seismic facies analysis is a key component of stratigraphic interpretation. It involves the characterization of seismic reflection patterns in terms of their configuration, continuity, amplitude, and frequency content. These characteristics can be related to specific depositional environments and lithologies (Posamentier and Kolla, 2003).

Sequence stratigraphy provides a powerful framework for stratigraphic interpretation of seismic data. Key sequence stratigraphic surfaces such as maximum flooding surfaces, sequence boundaries, and transgressive surfaces can often be identified in seismic data, allowing for the construction of a chronostratigraphic framework (Catuneanu et al., 2009).

Seismic attributes play a crucial role in stratigraphic interpretation. Attributes such as instantaneous frequency, spectral decomposition, and RGB blending can reveal subtle stratigraphic features that may not be apparent in conventional seismic displays (Chopra and Marfurt, 2008).

Advanced techniques in stratigraphic interpretation include seismic geomorphology, which involves the analysis of time slices and horizon slices to identify depositional features such as channels, fans, and lobes (Posamentier et al., 2007). Machine learning and AI techniques are increasingly being applied to automate aspects of stratigraphic interpretation, such as facies classification and sequence boundary identification (Zhao et al., 2015).

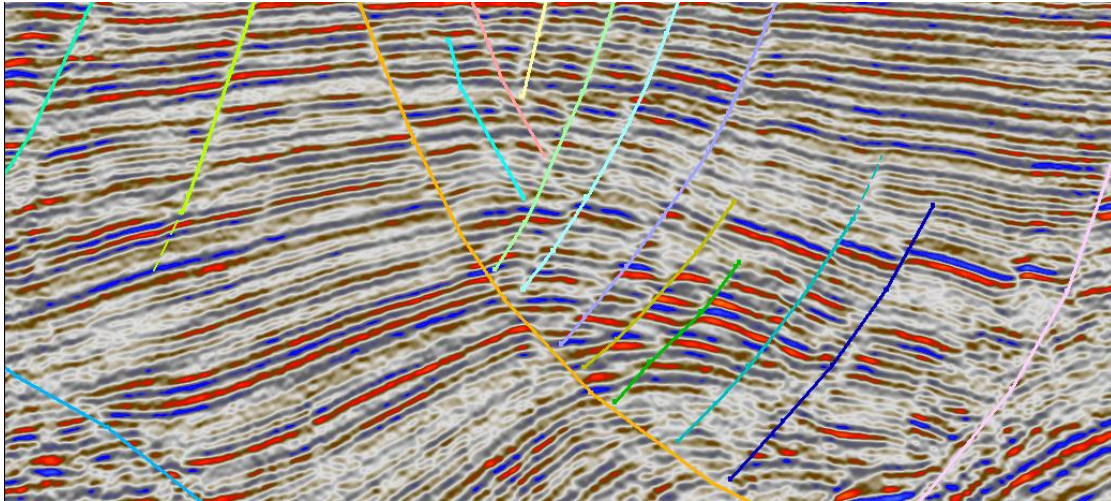


Fig. 15. Seismic data interpretation showing different structural and stratigraphic geology.

4.0 Applications of Seismic Reflection

4.1 Application of Seismic Reflection Geophysical Technique in Petroleum Exploration

Seismic reflection techniques have revolutionized petroleum exploration, providing high-resolution images of the subsurface that allow geoscientists to identify and characterize potential hydrocarbon accumulations. The application of these techniques spans the entire exploration and production lifecycle, from initial prospect identification to ongoing reservoir management (Sheriff and Geldart, 1995).

4.1.1 Prospect Identification

Seismic reflection data plays a crucial role in identifying prospective areas for hydrocarbon exploration. This process involves the integration of structural and stratigraphic interpretations to identify potential traps and reservoirs.

3D seismic data allows for detailed mapping of subsurface structures such as anticlines, fault blocks, and salt domes. Advanced attribute analysis, including coherence and curvature attributes, can highlight subtle structural features that may not be apparent in conventional seismic displays (Chopra and Marfurt, 2007).

Seismic facies analysis and sequence stratigraphy are key tools for identifying stratigraphic traps. Techniques such as spectral decomposition and RGB blending can reveal subtle stratigraphic features like channel systems, carbonate buildups, and pinch-outs (Posamentier and Kolla, 2003).

Seismic attributes such as amplitude anomalies, flat spots, and AVO (Amplitude Variation with Offset) responses can provide direct evidence of hydrocarbon accumulations. However, these indicators must be interpreted cautiously, as they can be ambiguous (Avseth et al., 2005).

Seismic data is crucial in developing and refining play concepts. Regional 2D and 3D surveys allow for the mapping of play elements across large areas, helping to identify sweet spots and assess play extent (Doust, 2010).

Recent advancements in machine learning and artificial intelligence are being applied to automate aspects of prospect identification, such as facies classification and anomaly detection (Zhao et al., 2015).

4.1.2 Reservoir Characterization

Once prospects are identified, seismic data plays a critical role in characterizing potential reservoirs, providing information about reservoir geometry, properties, and fluid content.

Reservoir Geometry: High-resolution 3D seismic data allows for detailed mapping of reservoir boundaries, internal architecture, and compartmentalization. Techniques such as seismic geomorphology can reveal depositional features that control reservoir distribution (Posamentier et al., 2007).

Seismic inversion techniques, including post-stack and pre-stack inversion, can provide estimates of rock properties such as porosity, clay content, and lithology. These predictions can be calibrated and validated using well data (Pendrel, 2001).

AVO analysis and elastic inversion can provide information about fluid content and saturation. Techniques such as extended elastic impedance (EEI) and lambda-mu-rho (LMR) analysis are particularly useful for discriminating between different fluid types (Goodway et al., 1997).

In fractured reservoirs, seismic anisotropy analysis can provide information about fracture orientation and density. Techniques such as azimuthal AVO and shear-wave splitting analysis are commonly used for this purpose (Gaiser and Van Dok, 2001).

Time-lapse seismic surveys allow for monitoring of reservoir changes during production. This technique is particularly valuable for understanding fluid movement and identifying bypassed pay (Johnston, 2013).

4.1.3 Risk Mitigation During Drilling Operations

Seismic data plays a crucial role in reducing risks associated with drilling operations by providing information about subsurface conditions and potential hazards.

Seismic velocities can be used to estimate pore pressure, helping to optimize mud weights and casing design. This is particularly important in areas with abnormal pressure regimes (Sayers et al., 2006).

High-resolution seismic data, particularly 3D seismic, can identify shallow hazards such as gas pockets, shallow water flows, and unstable sediments that could pose risks to drilling operations (Heggland, 2004).

Seismic-derived stress models can help predict zones of potential wellbore instability, allowing for optimized well trajectories and completion designs (Sayers, 2010).

Integration of seismic data with geomechanical models can provide information about in-situ stress orientations and magnitudes, critical for planning hydraulic fracturing operations in unconventional reservoirs (Goodway et al., 2010).

Real-time integration of seismic data with logging-while-drilling (LWD) data allows for precise well placement within reservoir targets, maximizing productive potential and avoiding hazards (Bacon et al., 2012).

4.1.4 Resource Assessment

Seismic data plays a crucial role in assessing hydrocarbon resources, both at the prospect level and on a regional scale.

Seismic-derived structural and stratigraphic maps form the basis for volumetric calculations of hydrocarbon in place. Uncertainties in these calculations can be assessed through probabilistic methods (Otis and Schneidermann, 1997).

Seismic inversion results can be used to map reservoir properties such as porosity and net-to-gross across entire fields or basins, allowing for more accurate resource estimates (Pendrel, 2001).

Regional seismic data allows for the assessment of play extents and the identification of sweet spots, crucial for portfolio management and exploration strategy (Doust, 2010).

Integration of seismic data with basin modeling techniques allows for the assessment of hydrocarbon generation, migration, and accumulation on a basin scale (Hantschel and Kauerauf, 2009).

Modern resource assessment techniques incorporate seismic uncertainties through methods such as geostatistical inversion and Monte Carlo simulation, providing probabilistic resource estimates (Dubrule, 2003).

4.2 Application of Seismic Reflection Geophysical Technique in Petroleum Production

Seismic reflection techniques have become integral not only in the exploration phase but also throughout the production lifecycle of hydrocarbon fields. The high-resolution subsurface imaging provided by these techniques enables more efficient and effective production strategies.

4.2.1 Well Placement Optimization

Optimal well placement is crucial for maximizing hydrocarbon recovery and minimizing production costs. Seismic reflection data plays a vital role in this process:

3D seismic data provides detailed information about reservoir geometry, internal architecture, and property distribution. Integrated reservoir characterization using seismic and well data allows for the identification of sweet spots and optimal drilling locations (Chopra and Marfurt, 2007).

Real-time integration of seismic data with logging-while-drilling (LWD) data enables precise well placement within reservoir targets. This is particularly important in thin reservoirs or those with complex internal architecture (Bacon et al., 2012).

In fractured reservoirs, azimuthal analysis of seismic attributes can provide information about fracture orientation and intensity, guiding horizontal well placement to maximize productivity (Gray et al., 2012).

Time-lapse seismic data can reveal fluid movement patterns within the reservoir, helping to optimize the placement of infill wells and avoid depleted zones (Johnston, 2013).

Pre-stack seismic inversion techniques provide estimates of reservoir properties such as porosity and fluid saturation, which can be used to guide well placement decisions (Avseth et al., 2005).

4.2.2 Enhanced Oil Recovery (EOR) Planning

Detailed reservoir characterization from seismic data is crucial for selecting appropriate (Enhanced Oil Recovery) EOR methods and optimizing their implementation. This includes identifying reservoir heterogeneities, flow barriers, and sweet spots (Li et al., 2015).

Time-lapse seismic surveys can track the movement of injected fluids (e.g., CO₂, polymers) during EOR operations, helping to assess sweep efficiency and identify bypass zones (Landrø, 2001).

In fractured reservoirs, seismic techniques such as azimuthal amplitude analysis and shear-wave splitting can provide information about fracture networks, crucial for designing effective EOR strategies (Gaiser and Van Dok, 2001).

Integration of seismic data with geomechanical models can help predict stress changes during EOR operations, particularly important for processes like hydraulic fracturing or thermal recovery (Goodway et al., 2010).

Specific seismic attributes, such as acoustic impedance and V_p/V_s ratio, can be used to predict reservoir quality and fluid distribution, guiding EOR planning (Chopra and Marfurt, 2007).

4.2.3 Monitoring Reservoir Performance

Repeated 3D seismic surveys allow for the detection of changes in fluid saturation and pressure over time, providing insights into reservoir behavior during production (Johnston, 2013).

Advanced 4D seismic analysis techniques can discriminate between pressure and saturation changes, crucial for understanding reservoir dynamics (Landrø, 2001).

Combining 4D seismic data with production data and reservoir simulation models allows for improved history matching and prediction of future reservoir behavior (Calvert, 2005).

In some reservoirs, 4D seismic can detect and monitor reservoir compaction, which can have significant implications for production and well integrity (Hatchell and Bourne, 2005).

Installation of permanent seismic sensors (either on the seafloor or in boreholes) allows for more frequent and cost-effective 4D seismic monitoring (Meunier et al., 2001).

4.2.4 Asset Management and Field Development

Seismic data forms a key component of integrated reservoir models, which are used for production forecasting, reserves estimation, and development planning (Doyen, 2007).

Geostatistical techniques applied to seismic data allow for the quantification of uncertainties in reservoir properties, enabling risk-based decision making in field development (Dubrule, 2003).

4D seismic and high-resolution 3D seismic can reveal areas of bypassed pay, guiding infill drilling programs and workover candidates (Johnston, 2013).

Seismic data provides crucial information for facilities planning, including the locations of subsurface hazards, optimal platform locations, and pipeline routes (Heggland, 2004).

Integration of seismic data with production data and reservoir simulation allows for ongoing optimization of production strategies, including water and gas injection (Calvert, 2005).

In mature fields, new seismic surveys (often with improved acquisition and processing techniques) can reveal new opportunities for field redevelopment (Lumley, 2001).

5.0 Case Histories

5.1 Case History 1: Integration of Seismic and Well Log Data for Reservoir Characterization in Offshore Niger Delta, Nigeria (Ismaila A.A and Ayomide O.A, 2024).

The demand for fossil fuels continues to rise globally, driving the need for efficient exploration and production strategies in both new and marginal fields. In the offshore Niger Delta, Nigeria, seismic reflection techniques, combined with well log data, have been extensively utilized to characterize hydrocarbon reservoirs, estimate reserves, and optimize production. This case history outlines the methodologies employed and the outcomes achieved in the study of an offshore field (referred to as the ATAGA field) in the Niger Delta (Ismaila A.A and Ayomide O.A, 2024).

The Niger Delta is a prolific hydrocarbon-bearing province located in the south-south region of Nigeria. It is bounded by the Calabar flank to the east, the Benin flank to the west, the Gulf of Guinea to the south, and older tectonic elements to the north. The delta covers an area of approximately 75,000 km², at Latitude 4° 30' N – 5° 20' N, with a sediment thickness exceeding 10 km in the basin depocenter. (Emujakporue, 2016) and (Okeke., *et al.*, 2018). The region's stratigraphy is divided into three formations: the Benin Formation, Agbada Formation, and Akata Formation, with the Agbada Formation being the primary hydrocarbon-bearing unit.

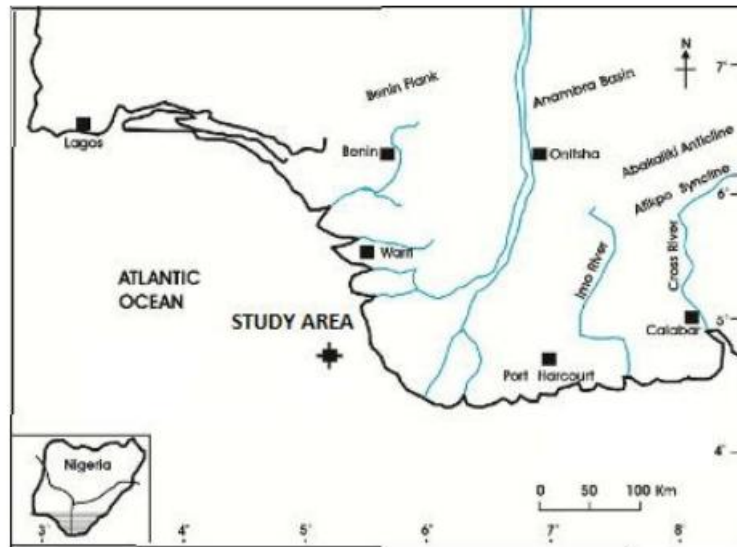


Fig 16 Location map of the study area (source: Ismaila, and Ayomide, 2024).

5.1.1 Methodology

The study employed an integrated approach, combining processed 3D seismic data with well log data from four wells (ATAGA 10, ATAGA 5, ATAGA 7, and ATAGA 11). The well log data, including gamma ray, resistivity, neutron, and density logs, were used to identify and characterize hydrocarbon-bearing reservoirs. The seismic data were interpreted to map structural features such as faults and horizons, which were then tied to the well logs using synthetic seismograms generated from check shot data.

5.1.2 Seismic Interpretation and Reservoir Delineation

The seismic reflection data were used to generate time and depth structural maps, which provided a detailed image of the subsurface. Eight faults were mapped, revealing the presence of synthetic and antithetic faults, as well as rollover anticlines. These structural features are critical in trapping hydrocarbons in the study area.

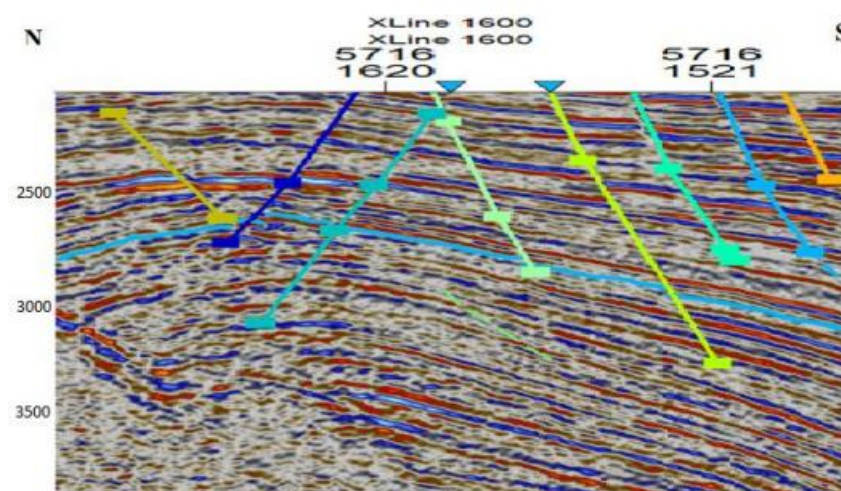


Fig 17 Seismic line showing the faults cutting through the different Seismic reflectors (source: Ismaila, and Ayomide, 2024).

The petrophysical analysis conducted on the well log data revealed several key properties of the reservoirs, including net-to-gross thickness ratio, porosity, shale volume, and water saturation. Four major reservoirs (A6, A7, A8, and A9) were identified across the wells. The average thickness of these reservoirs ranged from 56.6 m to 232.7 m, with water saturation varying from 0.29% to 0.57%. The average porosity of the reservoirs was between 0.18% and 0.22%.

5.1.3 Quantitative Results

The study's quantitative analysis included the estimation of the Stock Tank Oil Initially in Place (STOIIP) for the identified reservoirs. The STOIIP values ranged from 25 million stock tank barrels (MMstb) to 468 MMstb. This significant variation indicates the presence of substantial hydrocarbon reserves within the studied reservoirs. The integration of seismic reflection data with well log data proved effective in delineating these reserves, providing a reliable basis for further exploration and production activities.

5.2 Case History 2: Seismic Reflection Geophysics in the Agbami Field, Nigeria

The Agbami field is one of the largest deepwater discoveries in Nigeria, located approximately 220 km offshore in water depths ranging from 1,400 to 1,700 meters. The field was discovered in 1998 and is operated by Chevron Nigeria Limited in partnership with Famfa Oil, Statoil, and Petroleo Brasileiro Nigeria Limited (Adeoye et al., 2010).

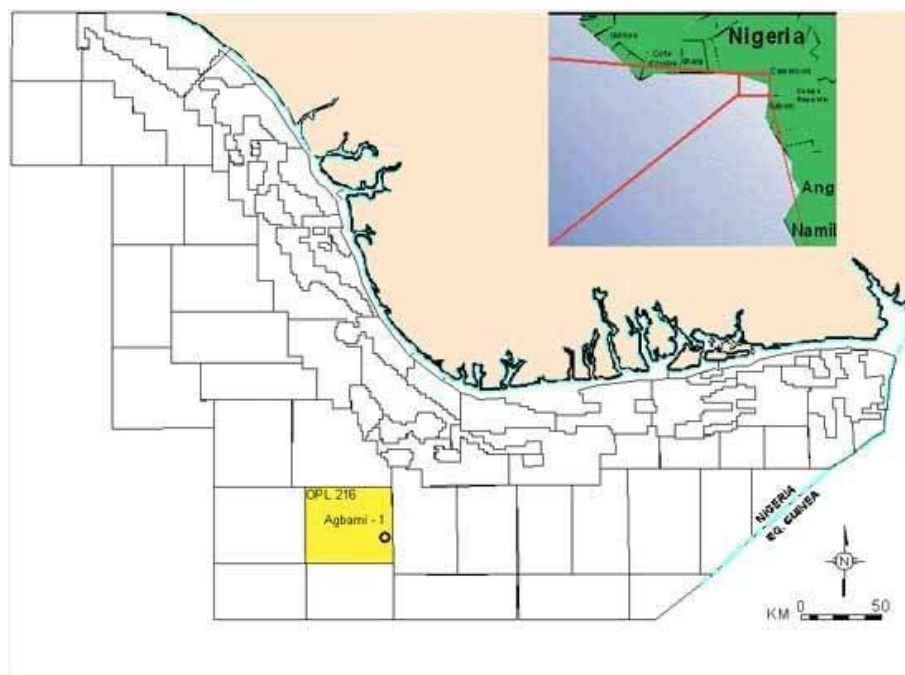


Fig 18 The Agbami oilfield is located 220 miles south-east of Lagos and 70 miles offshore Nigeria (Sankaran., et al 2011).

5.2.1 The Application of Seismic Reflection

In the late 1990s and early 2000s, multiple 3D seismic surveys were conducted over the Agbami area. These surveys employed long-offset, high-resolution acquisition techniques to

effectively image the deepwater turbidite systems. Advanced processing techniques, including pre-stack depth migration (PSDM), were applied to handle the complex wave propagation in the deepwater environment (Adeoye et al., 2010). The 3D seismic data allowed for detailed mapping of the turbidite channel systems that form the primary reservoirs in the Agbami field. Seismic attributes, particularly amplitude and coherence attributes, were crucial in delineating channel geometries and internal architectures (Fehintola et al., 2009).

Seismic inversion techniques were applied to derive acoustic impedance volumes, which were then used to predict reservoir properties such as porosity and net-to-gross ratio across the field. This integration of seismic and well data significantly improved the understanding of reservoir distribution and quality (Adeoye et al., 2010). As production commenced in 2008, 4D (time-lapse) seismic surveys were implemented to monitor reservoir performance. The first 4D survey was acquired in 2012, providing valuable insights into fluid movement within the reservoirs (Ojukwu et al., 2014).

5.2.2 Impact of Seismic Reflection Technique in the Agbami field.

The high-resolution 3D seismic data, combined with detailed reservoir characterization, allowed for optimal placement of production and injection wells. This resulted in higher per-well productivity and improved sweep efficiency (Fehintola et al., 2009).

The detailed reservoir characterization enabled by 3D seismic data led to more accurate reserve estimates. The initial recoverable reserves estimate for Agbami was around 800 million barrels of oil equivalent, but this was later revised upwards to over 1 billion barrels, partly due to improved seismic imaging and interpretation (Adeoye et al., 2010).

The comprehensive understanding of reservoir architecture and properties derived from seismic data allowed for an optimized field development plan. This included the strategic placement of subsea manifolds and the design of an efficient subsea production system (Fehintola et al., 2009).

The implementation of 4D seismic monitoring has enabled more effective reservoir management. By identifying areas of bypassed pay and tracking fluid movements, the operator has been able to optimize production and injection strategies, leading to improved recovery factors (Ojukwu et al., 2014).

The high-quality seismic data significantly reduced geological uncertainties, allowing for more confident decision-making in well planning and reservoir management. This has led to a reduction in non-productive time and drilling risks (Adeoye et al., 2010).



Fig 19 Agbami oilfield project is one of Nigeria’s largest deepwater developments (Mondol & Bjorlykke, 2010).

6.0 Implications Seismic techniques:

6.1 Implications for the Petroleum Industry

- i. Increased Exploration Success: Improved imaging and characterization capabilities will lead to higher exploration success rates, particularly in frontier and deepwater areas.
- ii. Enhanced Recovery: More accurate reservoir characterization and monitoring will enable optimized production strategies, leading to increased recovery factors and extended field life.
- iii. Cost Reduction: Advanced seismic techniques, particularly when combined with AI and machine learning, have the potential to significantly reduce exploration and production costs through more efficient decision-making.
- iv. Environmental Stewardship: Improved subsurface understanding will enable more targeted drilling and production strategies, potentially reducing the environmental footprint of oil and gas operations.
- v. Energy Transition: Seismic techniques will play a crucial role in the energy transition, both in maximizing recovery from existing fields and in supporting emerging technologies such as geothermal energy and carbon capture and storage.

7.0 Conclusion

Seismic reflection geophysical techniques have revolutionized the petroleum industry, playing a crucial role in both exploration and production phases. This research has

highlighted the fundamental principles of seismic reflection and its wide-ranging applications in the oil and gas sector. Advanced processing techniques, such as pre-stack depth migration and full-waveform inversion, have enhanced the resolution and accuracy of seismic images, particularly in complex geological settings. And also, the integration of seismic data with other geological and petrophysical information has enabled more comprehensive reservoir characterization, improving reserve estimates and development planning.

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