Shale Gas Reservoir Characterization: Understanding the Shale Types and Storage Mechanisms for Effective Exploration and Production

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Abstract

Shale gas refers to the natural gas trapped within shale formations, which are fine-grained sedimentary rocks rich in petroleum and natural gas resources. It exists in shale rocks as either free gas or adsorbed gas, resulting from the thermal alteration of kerogen, an insoluble organic matter. Shale acts as both the source and reservoir rock for shale gas. When the hydrocarbon generated inside the shale cannot be expelled to the reservoir rock, the shale itself becomes the reservoir. Various factors influence the gas generation and accumulation processes, including the extent and thickness of the shale layer, total organic carbon content, kerogen type, maturity, permeability, mineralogy, and brittleness versus ductility. Although shale rocks serve as both the source and reservoir, the extraction of shale gas requires hydraulic fracturing techniques such as acidization, propane injection, CO_2 fracturing, and other methods. The exploration of shale reservoirs involves assessing total organic content, porosity, micro-fractures, and the geometry of porous spaces. Therefore, integrated studies encompassing geological, geochemical, petro-physical, geophysical, geomechanical, and technical aspects are necessary to identify optimal areas for shale gas exploration, exploitation, and recovery.

Keywords

Shale · Sedimentology · Geochemistry · Reservoirs · Adsorption · Exploration

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1 Introduction

Shale is a common sedimentary rock composed of fine-grained particles, including clay minerals (such as kaolin), quartz, and calcite (Butt 2012; Ibad and Padmanabhan 2022). Its distinctive characteristic is its tendency to split into thin layers, known as fissility, with each layer being less than one centimetre thick (Zhang, 2019a). Shale can also be referred to as mudrock, encompassing clay-rich fissile mudrocks (Gu et al. 2018; Hawkins and Pinches 1992; Zhang et al. 2013). The color of shale varies based on the presence of different minerals, with red, brown, green, and black hues indicating the presence of ferric oxide, iron hydroxide, micaceous minerals, and carbonaceous material, respectively. Shale primarily consists of clay

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minerals, quartz, feldspar, carbonate minerals, and iron oxides (Hazra et al. 2016; Thickpenny 1984). Clay minerals like kaolinite, montmorillonite, and illite are the major components of shale, with the dominance of specific clay minerals varying depending on the age of the rock (Hazarika et al. 2023a, b). The transformation of clay minerals results in the formation of various minerals such as quartz, chert, calcite, dolomite, ankerite, hematite, and albite (Fan et al. 2015; Ruessink and Harville 1992). Shales contain a significant amount of organic matter, making up about 95% of the organic content in sedimentary rocks (El Nady and Hammad 2015). Black shales, formed in oxygen-deprived conditions, contain reduced free carbon, ferrous iron, and sulfur, which contribute to their dark colorationxrf (Schieber 2011). Shales are commonly found in marine environments with highly saline groundwater (Hazra et al. 2016; Kala et al. 2021a, b). The deposition of shale occurs in slow-moving water, such as lakes, lagoons, river deltas, floodplains, and offshore areas below the wave base. These sediments remain suspended in water for extended periods compared to larger particles like sand. Thick deposits of shale are often found near ancient continental margins and foreland basins. Black shales are prevalent in Cretaceous strata along the margins of the Atlantic Ocean, deposited in fault-bounded silled basins associated with the breakup of Pangea (Schieber 2011). The development of shale's fissility occurs during compaction, where clay particles become strongly oriented into parallel layers. Factors such as the clay composition and the binding of hydrocarbon molecules can influence the degree of fissility. During burial, shale undergoes diagenesis, which involves compaction, lithification, and mineralogical changes. Compaction and pressure solution lead to the reduction of pore space and the cementation of grains (Lash and Blood 2004; Xu et al. 2020; Zheng et al. 2022a, b). Lithification occurs through the deposition of cement and the alteration of clay minerals (Aird 2019). The deeper burial stages are associated with the highest degree of compaction and lithification (Moore and Wade 2013; *The Petroleum System Introduction and Definitions*, n.d.-b). When shale is exposed through erosion, additional changes occur due to meteoric water, including dissolution of cement and oxidation of pyrite (Mahoney et al. 2019).

Shale is an important source rock for hydrocarbons, including natural gas and petroleum (Hazarika et al. 2023a, b). Its fine particle size and lack of strong currents in the depositional basin contribute to the preservation of organic matter. Over time, the organic matter undergoes chemical changes, transforming into kerogen, which can further convert into graphite and petroleum under higher temperatures and pressures at greater burial depths (Rabbani and Babaei 2021; Zhang et al. 2012, 2013).

1.1 Classification of Shales

Shales are a type of sedimentary rock that forms through the transportation, deposition, and compaction of silt and clay particles. Their main distinguishing characteristic is their fissility, which refers to the property of easily splitting along thin, closely spaced parallel layers. Shales can be classified based on various observable features and the environment in which they were deposited (Okeke and Okogbue 2011a). A brief description about shale classification is given below,

Texture-based classification: Shales are typically composed of fine-grained silt and clay particles, with the dominant constituent determining their classification. If silts dominate, they are called silty shale, and if clays dominate, they are called clay shale. When shales contain significant amounts of sand, they may be referred to as sandy shale or arenaceous shale (Jiang et al. 2017; Okeke and Okogbue 2011a; Slatt 2011).

Mineralogical composition-based classification: Shales can be classified as quartzose, feldspathic, or micaceous shale, depending on the predominant presence of quartz, feldspar, or mica minerals, respectively, as determined through X-ray diffraction (XRD) analysis (Fan et al. 2015; Ruessink and Harville 1992).

Cementation-based classification: Shales, like other sedimentary rocks, are cemented by minerals or elements after deposition and compaction. The dominant cementing material can be used for classification, as it can affect the properties and performance of the shale. Common cementing materials include silica, iron oxide, and calcite or lime, leading to classifications such as siliceous, ferruginous, or calcareous (limy) shales (Athy 1930; Bjørlykke 2015).

Depositional environment-based classification: Shales are deposited in various sedimentary environments, including lacustrine (continental), deltaic (transitional or marginal), and marine environments (Kala et al. 2021a, b). Shales deposited in lacustrine environments contain a mixture of clay, silt, and sand, inorganic carbonate precipitates, and various freshwater invertebrate organisms and plant deposits (Thickpenny n.d.; Zhao et al. 2017). Deltaic shales are characterized by alternating marine transgressions and regressions, shallow depth, and a concentration of kaolinite/illite/montmorillonite clay minerals. Marine shales are typically darker in color, richer in marine planktonic fossils, and found in deeper environments with oxygen deficiency and a concentration of illite/montmorillonite clay minerals (Chutia et al. 2013; Ghosh et al. 2022; Hayashi et al. 1997).

Organic matter content-based classification: Shales can be classified as carbonaceous or bituminous based on their organic matter content. Carbonaceous shales contain dominant organic matter from plant fragments such as pollen grains, stems, and leaves, indicating a continental or transitional depositional environment. Bituminous shales contain dominant organic matter from animal fragments such as fossils, typically associated with deltaic or marine environments. Both carbonaceous and bituminous shales serve as important source rocks for petroleum oil and gas generation, depending on their kerogen content (Hu et al. 2017; Mroczkowska-Szerszeń et al. 2015; Tanykova et al. 2021; Zhang et al. 2012).

Strength-based classification: The strength of shales can be assessed using the slake-durability index, which measures the resistance of the rock to cycles of wetting and drying (Selen et al. 2020; Singh et al. 2005). Shales with a slake-durability index below 80% are classified as soil-like, while those with an index above 80% are classified as rock-like. Soil-like shales undergo Atterberg Limits tests to determine their plasticity index, while rock-like shales are subjected to point load strength tests. The strength characterization of shales can also be derived from stress/strain curves, where soft rocks exhibit ductile behavior and hard rocks exhibit brittle behavior.

Properties of shales: Shales exhibit various petrophysical and geomechanical properties that are used in engineering evaluations. Petrophysical properties include density, porosity, permeability, and clay content, while geomechanical properties include plasticity index, slake-durability index, swelling potential, hardness, point-load strength (tensile), uniaxial compressive strength (Ahmad 2014; Bai et al. 2016; Hazarika et al. 2019).

1.2 Shale as Source Rock and Reservoirs

Shales play a crucial role as source rocks in the generation of petroleum. Certain favorable conditions need to be met for a source rock to have the potential to generate petroleum. These conditions are outlined by various researchers. Total organic carbon (TOC) content: The source rock should have a TOC content greater than 0.5%. Organic matter in the rock contributes to the generation of hydrocarbons. Hydrogen index (H1): The hydrogen index, which represents the hydrogen content of the organic matter, should be greater than 150 mg Hc/g TOC. A higher hydrogen index indicates a higher potential for hydrocarbon generation Wotanie et al. 2022).

Oxygen index: The oxygen index, representing the oxygen content of the organic matter, should be less than 160 mg CO_2/g organic carbon (org.C). A lower oxygen index indicates favorable conditions for hydrocarbon generation.

Liptinite content: Liptinite is a type of organic maceral that includes certain organic compounds with a high hydrogen content. The source rock should have a liptinite content greater than 15%, indicating a higher potential for petroleum generation.

Temperature range (Oil window): The temperature range within the source rock, known as the oil window, should typically be between 100 and 250 °C. This range is conducive to the transformation of organic matter into petroleum.

Vitrinite reflectance: Vitrinite is another organic maceral that reflects light. The vitrinite reflectance (Ro) should range from 0.5 to 1.2%. This parameter indicates the maturity of the organic matter and its potential to generate petroleum.

Additionally, sufficient organic matter of the right quality, favorable chemical composition of the kerogen, and an appropriate thermal history are also important factors for petroleum generation, as outlined by Tissot. Petroleum traps can be categorized as structural or stratigraphic. Shales play a role in both types of traps. In structural traps, which involve folded or faulted formations, shale acts as a cap or seal rock, preventing the upward migration of hydrocarbons. In stratigraphic traps, which result from facies changes or the presence of coral reefs, shale can act as a seal rock. Shale smears, where shale forms a barrier to fluid migration, are also known to act as seal rocks. In petroleum-rich regions like the Niger Delta, North Sea, and Gulf of Mexico, both structural and stratigraphic traps with shale seals are commonly found, facilitating the accumulation of petroleum. Shales, traditionally considered impermeable, can become viable reservoirs for oil or gas when they undergo natural or induced fracturing. Natural fracturing in shales occurs due to volume changes associated with compaction at great depths. These fractures, often vertical and continuous, are known as joints and can enhance permeability. Systematic fractures occur in parallel sets and intersect other joints or discontinuities, while dip joints are perpendicular to bedding planes (Harding and Lowell 1979; Hill et al. 2007; Okeke and Okogbue 2011b). Naturally fractured shale gas reservoirs, such as the Devonian shales in the Appalachian Basin, Michigan Basin, and Illinois Basin in the United States, have been successfully producing gas since the mid-1980s. Although production rates are generally low (20–200 thousand cubic feet per day), these wells have long life spans. The recovery efficiency of gas in place is also relatively low (5–10%). To optimize gas extraction, horizontal wells are typically drilled into the shale to maximize contact with the gas pay zone. Through fracturing, shale reservoirs can achieve increased permeability, allowing for the accumulation and economic extraction of oil or gas. This reframe acknowledges the transformative potential of fracturing in shale reservoirs, enabling them to serve as productive reservoirs for hydrocarbons (Barati and Liang 2014; Donaldson et al. 2014; Moore and Wade 2013; Wanniarachchi et al. 2017).

2 Shale Reservoir Characterization

In recent years, shale gas resources have gained prominence as a viable energy source, thanks to successful developments in the Mississippian Barnett Shale in the Fort Worth Basin using hydraulic fracturing and horizontal drilling (Hill et al. 2007; Loucks et al. 2009). This breakthrough led geoscientists to explore other shale basins in the United States, such as the Devonian Antrim Shale in the Michigan Basin, Devonian Ohio Shale in the Appalachian Basin, Devonian New Albany Shale in the Illinois Basin, and Cretaceous Lewis Shale in the San Juan Basin (Dong et al. 2019; Dong and Harris 2020; Lash and Blood 2004). Subsequently, the Fayetteville Shale in Arkansas and the Woodford Shale in Oklahoma were also developed in 2004, followed by the Haynesville Shale in 2008 (Chopra et al. 2012). The development of these shale formations challenged the traditional approach of gas generation in source rocks followed by migration into separate reservoir rocks. Shale gas formations serve as both the source and reservoir rocks, eliminating the need for migration. Due to their near-zero permeability, shale formations act as their own seals (Hazarika et al. 2023a, b). The gas within these formations can be trapped as free gas in natural fractures and intergranular porosity, as gas sorbed into kerogen and clay particle surfaces, or as gas dissolved in kerogen and bitumen. Shale gas reservoirs have specific characteristics that determine their potential as productive shale gas plays. These include organic richness (total organic carbon content), maturation level (reflected by vitrinite reflectance), thickness, gas-in-place, permeability, mineralogy, brittleness, pore pressure, and depth (Huang et al. 2020). The optimal combination of these factors contributes to favorable productivity (Boruah et al. 2019; Boruah and Ganapathi 2015).

2.1 Geological and Geohysical Analysis

Given the varying properties of different shale gas reservoirs, it is essential to conduct thorough studies before implementing any exploitation plans. Geophysical workflows, utilizing 3D surface seismic data, are employed to characterize shale gas formations (Chopra et al. 2012). One approach involves using well log data, where resistivity measurements can indicate the presence of nonconducting hydrocarbons in mature rocks (Liu et al. 2018). The ΔlogR technique, proposed by Passey et al. (1990), utilizes scaling of transit time and resistivity curves to identify organic-rich intervals and estimate total organic carbon (TOC) content, which is linearly related to maturity (Kamali and Mirshady 2004). Other attributes from log curves, such as sonic, density, resistivity, and porosity, can be crossplotted to gain further insights and distinguish reservoir zones from non-reservoir zones (Moore et al. 2011; Ogiesoba and Hammes 2014). Løseth et al. (2011) demonstrated the possibility of establishing a relationship between TOC values and acoustic impedance through crossplotting measurements from cores and well logs (Løseth et al. 2011). This relationship can be used to transform acoustic impedance volumes into TOC volumes derived from simultaneous inversion. Shale gas logs typically exhibit high gamma ray readings, high resistivity, and low photoelectric effect due to the presence of kerogen (Fertl et al. 1980). Gamma ray logs can serve as a proxy for predicting TOC content (Lüning and Kolonic 2003). Natural Gamma Ray Spectroscopy (NGS) logs aid in lithology interpretation and can differentiate carbonaceous layers (uranium-rich) from true shales (thorium/potassium-rich), influencing lateral continuity probabilities (*7-Natural-Gammaray-Spectrometry-1984*, n.d.; Klaja and Dudek 2016). Formation Micro-Imager (FMI) logs are useful for identifying fractures, fracture networks, structures, and rock textures (Watton et al. 2014). These geophysical workflows and log interpretations provide valuable information for characterizing shale gas formations, understanding their properties, and identifying reservoir zones for successful exploitation.

Seismic studies play a crucial role in shale gas exploration, providing valuable information for various purposes. These include the delineation of shale gas beds, determining their thickness and areal extent, estimating closure stress in combination with amplitude-versus-offset (AVO) analysis, identifying optimal areas for hydraulic fracturing, and demarcating zones for fracturing. Researchers have utilized different seismic methods and attributes to study shale gas resources. For example, Gupta (2013) and Guo et al. (2010) used coherence and most-negative principal curvature to map lineaments correlated to subtle faults seen on vertical seismic data in the Anadarko Basin and Arkoma Basin, respectively (Guo et al. n.d.; Gupta et al. 2013). Hill et al. (2002) reported the high spatial variability of petrophysical and petrochemical properties in the Marcellus formation. In 1976, Jaeger and Cook studied the mechanical properties of shale, specifically brittleness and ductility, using seismic data. The seismic properties of kerogen in shale formations exhibit characteristics such as low density (~ 1.3 g/cc) and low velocity. This can result in high amplitude and low impedance reflections, similar to coal, under favorable conditions.

2.2 Geochemical Analysis

Geochemical analysis is another important aspect of shale gas exploration. The hydrocarbon generation potential of shale depends on factors such as the presence of organic matter (at least 0.5% weight), types of organic matter (which determine gas, oil, or both), and thermal maturity. Maturity can be determined using various indicators, including vitrinite reflectance, thermal alteration index, fluorescence, and Lopatin's time–temperature index. Vitrinite reflectance, which measures the reflection of light on the surface of vitrinite, is a widely used method (Hayashi et al. 1997; Kala et al. 2021a, b; Rackley 2017; Singh and Chakraborty 2021).

The permeability of shale is generally negligible, and gas production in commercial quantities requires fractures to provide permeability (Grathoff et al. 2016). Horizontal wells are often used in shale gas formations because natural fractures or joints in most shale formations are vertical (Lecampion et al. 2017). By drilling vertically to the target formation and then horizontally through the shale, more vertical fractures can be intersected. Multistage stimulation treatments, including hydraulic fracturing, are performed to create and extend fractures around the wellbore. Proppant injection is also important to keep the fractures open, and different proppants and fracturing fluids are used depending on the characteristics of the shale formation (Donaldson et al. 2014; LaFollette and Hurt 2016; Montgomery and Smith 2010; Qian et al. 2020a, 2020b).

2.3 Laboratory Characterization

The Helium Porosimeter is a valuable tool used to measure the porosity of rocks and calculate their grain density. It plays a crucial role in determining permeability through air by utilizing Ultraperm 400, which relies on steady-state gas flow measurement. This equipment combines data acquisition and real-time graphical display with mass flow, providing more accurate and precise permeability data.

X-ray powder diffraction (XRD) is a rapid analytical technique primarily used for identifying the crystalline phase of a material. It helps in determining unit cell dimensions and is particularly useful for identifying unknown crystalline materials. XRD analysis involves finely grinding and homogenizing the material, determining its average bulk composition, and then scanning it using an X-ray diffractometer after powdering it to 300 mesh using the Fritsch Micro Pulverisette-7 instrument (Josh et al. 2012; Kurtulus et al. 2012; Muktadir et al. 2021).

The scanning electron microscope (SEM) uses a focused beam of high-energy electrons to generate various signals from the surface of solid specimens. SEM is commonly used to generate high-resolution images and assists in identifying phases based on qualitative chemical analysis and crystalline structure. Operating at voltages between 10e20 kV, SEM allows for magnification of up to 20,000×. X-ray microtomography is another technique that can be used to create a 3D virtual model of a specimen without damaging the original sample. Microtomography scanners provide isotropic or near isotropic resolution, allowing for alternative representations of the volume by stacking individual slices (Chandra et al. 2023; Hazra et al. 2016; Sohail et al. 2020; Zheng et al. 2022a, 2022b).

Before evaluating a field for shale gas, it is essential to acquire total organic carbon (TOC) and vitrinite reflectance (VRO) data from the formation (El Nady and Hammad 2015; Kar et al. 2022; Pan et al. 2020). Conventional core or side wall core analysis is the preferred method for acquiring this data. Combining these properties with basin modeling studies can provide valuable insights into the hydrocarbon potential volume. Petrophysical analysis encompasses both core analysis and log analysis, which involve determining physical rock properties based on lithological characteristics, identifying sedimentary structures, and analyzing lithology, visible fractures, and partings. A typical shale gas log displays high gamma values, high resistivity, and low photoelectric effects due to the high concentration of kerogen and low water saturations.

Geomechanical studies play a vital role in identifying sweet spots in shale gas reservoirs. Unlike conventional plays that primarily focus on wellbore stability or sand production, shale gas reservoirs require extensive core and core plug studies. The Vp/Vs ratio and P-impedance can be used to differentiate shale reservoirs from non-reservoir shales, with shale gas reservoirs typically exhibiting lower Vp/Vs ratios (Alam et al. 2021; Sohail et al. 2020; Vermylen 2011).

Figure 1 shows an example from the Barren Measures Formation of the Raniganj Field, and their classification the shale based on laboratory

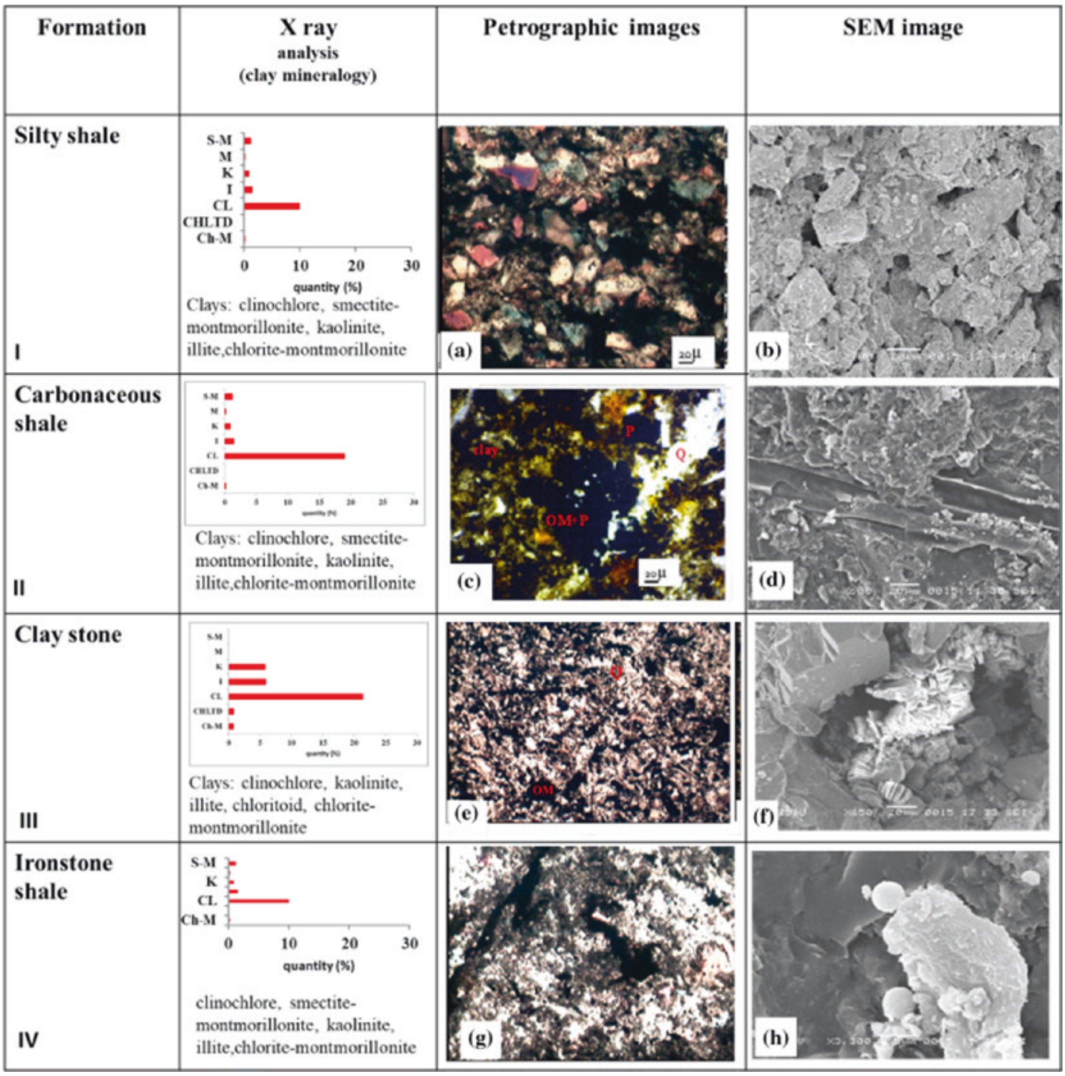

Fig. 1 Classification of lithofacies of Barren Measures shale based on mineralogy, petrography and scanning electron microscopy. I. Silty shale: photomicrographs **a** and **b** illustrate sub rounded quartz grains coated with clays. II. Carbonaceous shale: Photomicrographs **c** and **d** indicate presence of organic matters where grains are coated with iron. III. Claystone: **e** indicates presence of clays; **f** booklet type of kaolinite clays. IV. Ironstone shale: **g** iron precipitation in the microfractures; **h** iron nodules (Boruah and Ganapathi 2015)

analysis of the shale samples (Boruah et al. 2019).

Reservoir properties analysis has increasingly been carried out at the nanometer scale to understand pore geometry, organic material storage, hydrophobic pore walls, and gas-wetting in shale reservoirs. The location, distribution, and amount of organic matter within gas shales are crucial parameters for estimating gas reserves. However, the understanding of connectivity between different pore and wettability systems remains limited. Shale gas flow is controlled by diffusion, adsorption, and desorption mechanisms, with viscous flow, Knudsen diffusion, and molecular diffusion being the main types. Efforts are ongoing to develop numerical simulators that incorporate flow modelling in mixed wettability systems (Kudapa et al. n.d.; Michel et al. 2011; Tian et al. 2014; Zhang 2019a, 2019b, 2019c).

Exploring and exploiting shale gas reservoirs require a comprehensive approach that integrates various techniques. Geological, geochemical, geophysical, and reservoir characterization techniques are employed to gain a thorough understanding of the shale reservoir. Advanced laboratory techniques, including micro to nano scale imaging techniques, are crucial for studying the shale reservoir and its properties (Hazra et al. 2016; Sohail et al. 2020). These techniques help in analyzing the pore structure, organic content, and connectivity within the reservoir, providing valuable insights for efficient exploration and exploitation processes (Fig. 2) (Chopra et al. 2012).

Understanding the pore-size distribution of shale is crucial for estimating its transport and storage behaviour (Fig. 3). Shale possesses complex multiple-scale pore structures that are more intricate than those found in conventional

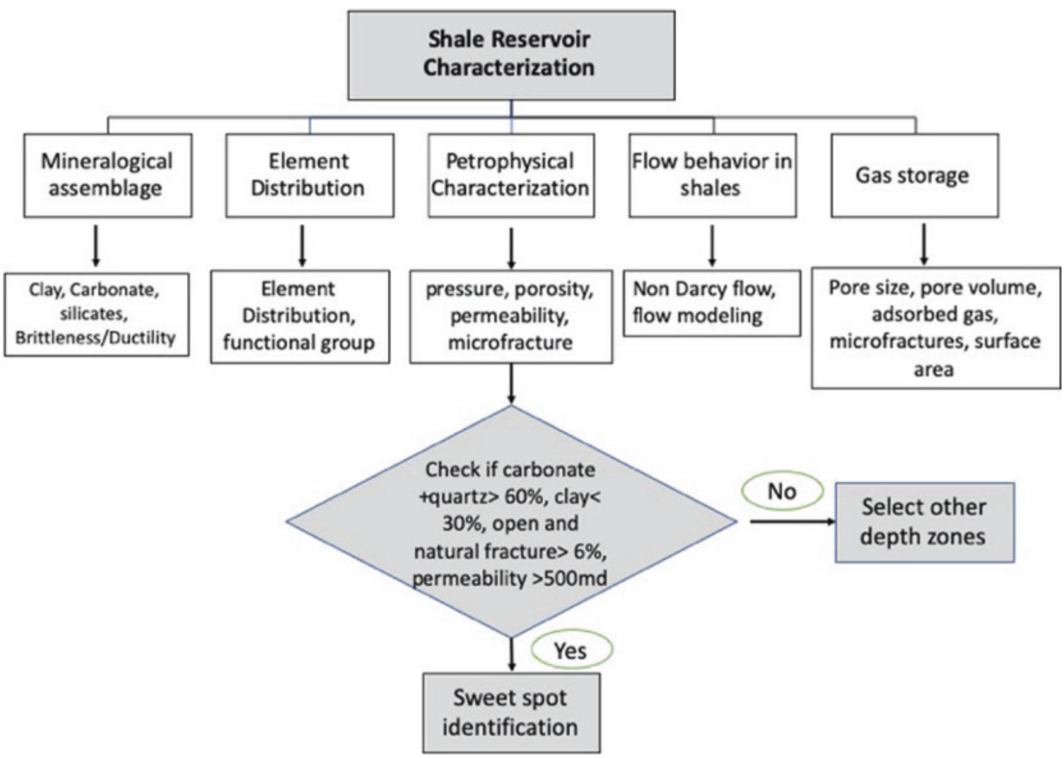

Fig. 2 Flow chart for shale reservoir characterization

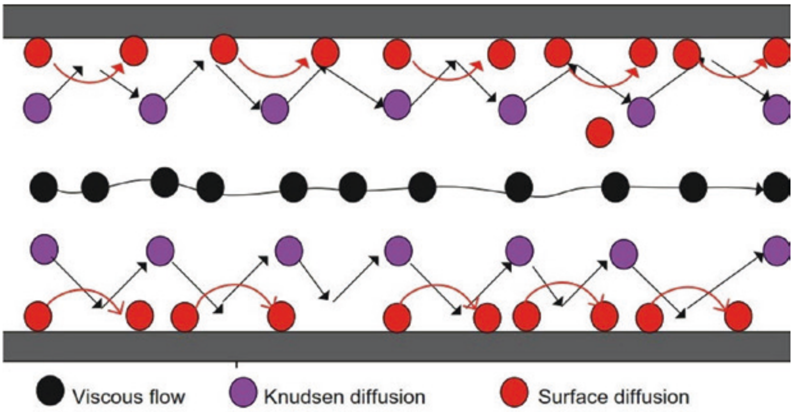

Fig. 3 Gas flow in the shale reservoir

reservoir rocks (Kuila and Prasad 2013a). Despite having low porosity, shale has the ability to hold a significant amount of natural gas in an adsorbed state on its internal surfaces (Kuila and Prasad 2013b; Loucks et al. 2009). The Brunauer–Emmett–Teller (BET) theory is commonly used to explain the physical adsorption of gas molecules on a solid surface and is applied in the measurement of the specific surface area of shales (Brunauer, Emmett, Teller 1938). This technique involves multi-layer adsorption using non-corrosive gases such as nitrogen, argon, or carbon dioxide as adsorbents to determine surface area data (Farajzadeh et al. 2009; Macht et al. 2011; Matthias Thommes et al. 2013; Wang et al., 2020). The methane sorption capacity, specific surface area, and pore size distribution of shale can be quantified using the N_2 gas adsorption technique, which allows examination of fine pores within the range of 1.7–200 nm (Bustin et al. 2008a, 2008b; Chalmers et al. 2012; Ross and Marc Bustin 2007, 2009).

2.4 Reserve Estimation

There are several numerical equations to estimate the shale gas reserves, which combines both the free and adsorb gases. Mavor et al. (1996) proposed the numerical equations for free gas and adsorbed gas calculation (Mavor et al. 1996).

3 Horizontal Drilling and Hydrofracturing

Horizontal drilling is an effective technique that minimizes land disturbance by allowing multiple wells to be drilled from a single drilling pad. This approach increases the exposure of the wellbore to the shale rock, thereby enhancing the recovery of natural gas from the shale formation (Kim et al. 2015; LaFollette and Hurt 2016; Qian et al. 2020c). Horizontal drilling, combined with hydraulic fracturing (fracking), is the current method used for efficient production from unconventional reservoirs (Zheltov and Khristianovich 1955).

Hydraulic fracturing, commonly known as “fracking,” is a method of extracting natural gas and oil from underground rock formations by injecting high-pressure fluid into the rocks to create fractures. These fractures then allow the trapped hydrocarbons (such as natural gas and oil) to flow more easily to the wellbore and be extracted. Rocks with low permeability, typically less than 1 millidarcy (mD), are ideal candidates for stimulation through hydraulic fracturing. The process involves injecting a high-pressure fluid into the wellbore, exerting enough pressure to fracture or break down the rock formation (Barati and Liang 2014; Gandossi 2013a, 2013b; Lecampion et al. 2017; Möri and Lecampion 2021; Rutqvist et al. 2013;

Shimizu et al. 2011; Snapshot and Overview 2021; Stanisławek et al. 2017; Zhao et al. 2014).

The first instance of hydraulic fracturing took place in 1947 in the Hugoton field, Kansas, on a gas well operated by Pan American Petroleum Corp (LaFollette and Hurt 2016). The initial fracturing fluid used, called NALPALM, was a costly and hazardous composition consisting of a gasoline gel mixed with palm oil and cross-linked with naphthenic acid (Arwini 2016). However, in subsequent years, safer fracturing fluids were developed, with water being the primary base fluid. Proppants such as clay, sand, and ceramics are often added to the water-based fluids, and cross-linked fluids using polymers, gelling agents, stabilizers, and breakers are also employed.

Hydraulic fracturing is performed by pressurizing the wellbore to a level higher than the formation's breakdown pressure, ensuring that fractures are created in the rock formation. This process allows for increased permeability and improved flow of oil and gas to the well for extraction. The use of proppant particles in the fracturing fluid is crucial for the success of hydraulic fracturing. These particles serve to suspend in the fluid and hold open the complex network of fractures created during the fracturing process. As the mixture reaches the horizontal section of the wellbore, it is released through the perforations into the surrounding rock at high pressure, contributing to the creation of microfractures. This network of cracks allows the natural gas to flow through and reach the production well, enabling the extraction of gas reserves from the shale formation (Zhao et al. 2014).

Hydraulic fracturing plays a significant role in enhancing the permeability of the reservoir rock and improving shale gas production. However, shale formations are sensitive to water, and the use of conventional fracturing fluids in shale reservoirs can lead to issues such as formation damage, clay swelling, and instability. Mineral hydration and water imbibition can reduce the effective permeability of the rock, while the improper disposal of large volumes of flowback fluids containing chemical additives can pose environmental concerns.

Therefore, there is a current need to develop environmentally friendly fracturing fluids and utilize appropriate hydrofracturing technologies with limited fluid usage. Recent research has explored the application of waterless fracturing fluids to mitigate environmental issues, and laboratory investigations have shown the effectiveness of liquid carbon dioxide (CO_2) as a hydrofracturing fluid (Hazarika and Boruah 2021). CO_2 fracturing has been suggested as a favorable technique due to its multiple benefits, including carbon sequestration, increased production, and reduced environmental hazards (Cai et al. 2007; Wang et al. 2013; Zhao et al. 2021).

4 Conclusion

In conclusion, shale rocks exhibit compositional variations, with higher clay mineral content indicating a higher likelihood of fissility. Heterogeneity of shale reservoirs is a crucial factor in commercial shale gas production. Technological advancements in hydraulic fracturing and horizontal drilling have been key to the successful development of shale gas plays. Integrated studies involving geology, geophysics, geochemistry, petrophysics, and geomechanics can help delineate potential shale plays and identify sweet spots for shale gas exploration and exploitation.

Shale gas resources have emerged as a highly promising energy source to meet the growing future energy demand. These resources are primarily found in organically rich ($>2\%$) and mature to post-mature shales with a brittle mineral composition. These shales serve as excellent sources and reservoirs for shale gas exploration. However, due to their impermeable nature and nano-scale pores, natural micro fractures are crucial for the extraction of natural gases. Artificial fracturing techniques, such as hydraulic fracturing, can be employed to stimulate the shales and enhance gas extraction.

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