Chapter 8
Unconventional Petroleum Reservoirs

In this chapter will present an overview of unconventional natural resources definitions and assessment. In this chapter will present an overview of unconventional natural resources definitions and assessment. Whereas, a different characterization have been presented to defined most of the unconventional reservoirs. The chapter covers most of the geological reservoirs include tight gas, tight oil, oil sands, oil shale, bitumen, gas shales, coalbed methane, and gas hydrates formations. This chapter discussed petroleum accumulation, reservoir fluids quantifications (porosity, permeability, and fluid saturations, Total oil contents), formation evaluation, and applications used to develop unconventional reservoirs.

8.1 Introduction

Unconventional petroleum studies have established intensely in the recent years. There are many studies were conducted in the sections of reservoir geology, geophysics, engineering, and economic evaluation. Unconventional petroleum is known as continuous or sub-continuous accumulations of hydrocarbons resources (Zhao et al. 2016a). Typically, unconventional petroleum is split into unconventional oil and natural gas resources. There is no specific definition of unconventional petroleum resources. Some researchers defined unconventional resources based only on the permeability values and others their definition was based either on the understanding of the petroleum system or product type. For instance, shale and tight sand reservoirs contain gas, wet gas, Heavy oil, and oil sands and oil fairways were classified as unconventional resources, where the permeability for such reservoirs can be above 500 nD. Besides, the unconventional reservoir can be either high or low permeability reservoir with both high and low viscosity fluids (Harris 2012). These resources can't produce by using conventional techniques. Therefore, new methods are required to increase reservoir permeability and fluid viscosity. Geologically extensive accumulations of petroleum are trapped in low permeability rock such as shale and siltstone with widespread boundaries and no clear traps or hydrocarbon-water contacts.

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https://doi.org/10.1007/978-3-030-28140-3_8

Unconventional resources include shale gas, tight oil, tight gas, coalbed methane, Bitumen, and gas hydrates (Gruenspecht 2011).

To make these Unconventional resources produce petroleum, the reservoir needs to exhibit very high hydrocarbon saturation, S_o or S_g and small S_w. Normally, the natural fracture may also take place, either sub-vertical fracture or horizontal fracture. These reservoirs have very low Permeability, often within nanodarcy range. Generally, the cost of the Unconventional oil production is usually more than conventional oil production and is possible can make additional environmental damage.

8.2 Unconventional Petroleum Geology

Unconventional hydrocarbon accumulation is referring to oil and gas continuous diffusion. Because of Pore-throats at the nanometer measure control, there is no clear trap and source rock description; also there are no identical contacts between gas and oil or between oil and water. Besides, the oil and gas saturation differs significantly with coexisting oil, gas, and water. Where, the diameter of the pore-throats is between the ranges of 100–500 nm, which will impact the unconventional hydrocarbon accumulation mechanism. In the unconventional system, there is no identical pressure system or clear bottom water boundary, also the hydrocarbon volume of each pore-cavity is differing significantly. Generally, the geological characteristics, evaluation methods, and classification systems between unconventional and conventional hydrocarbon resources are completely differences. Figure 8.1 below displays the petroleum systems of conventional resources and unconventional resources (Zou et al. 2011).

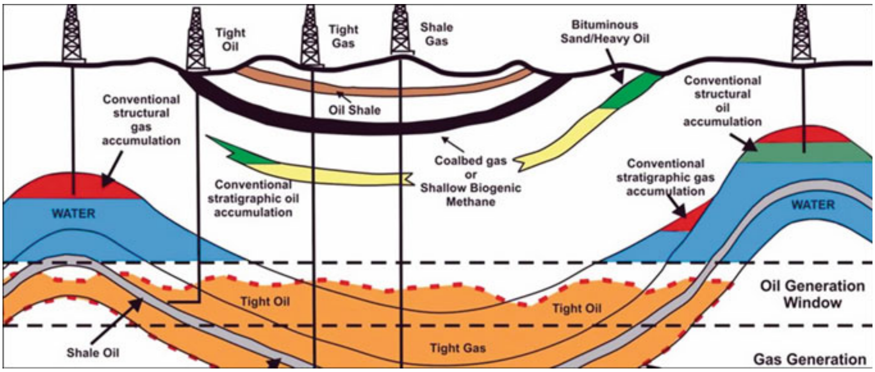

Fig. 8.1 Schematic shows the multiple different types of petroleum systems. *Source* Steve Sonnenberg1 and Larry Meckel (2016)

8.3 Types of Continuous Petroleum Accumulation

Currently, there is no accessible classification system for continuous petroleum accumulation as a way that classified for conventional petroleum accumulation. In this section, we present some classification schemes based on the features of the accumulations (Table 8.1). According to the previous exploration regions, unconventional petroleum accumulations may be classified into seven unconventional formations. Also, the deposits can be classified into the thermal genetic hydrocarbon, bio-genetic hydrocarbon, and mixture genetic hydrocarbon. The oil and gas existence type can be also absorption, isolated, or combination.

Table 8.1 Classification for continuous petroleum accumulation

Basis of classification		Type
Reservoir type		Tight-sandstone gas, tight-sandstone oil, shale gas, shale oil, fractured-vuggy carbonate petroleum deposits, volcanic and metamorphic petroleum deposits, CBM, gas hydrate, and others
Oil and gas origin		Thermal, biogenetic, mixed cause petroleum deposits
Source-reservoir-seal assemblage	Source-reservoir assemblage	Self-generated-reservoir (CBM, shale gas, shale oil, and others), non-self-generated-reservoir (tight-sandstone oil, tight sandstone gas)
	Petroleum source	Self-source deposits (CBM, shale gas, shale oil, and others), nonself-source deposits (tight-sandstone oil, tight-sandstone gas)
Oil and gas occurrence		Adsorption type, free type, adsorption-free type
Continuity		Gas deposits with continuous accumulation processes, continuous accumulation areas, and continuous exploitation processes

Source ZOU (2011)

8.4 Methods and Technologies

The main geological principle of unconventional hydrocarbon is the reservoir and diffusion of continuous petroleum accumulations. Superior technologies are required during the study of the unconventional hydrocarbon accumulations, such as reservoir prediction, micro-seismic, large-scale fracturing etc. Furthermore, resource evaluation approaches are totally different.

The exploration methods and technologies used for conventional resources can't be used for unconventional hydrocarbon accumulations. Normally, the porosity is less than 10% and the air permeability is lower than 1×10^3 mm^2.

8.5 Defining Unconventional Oil and Gas Resources

Unconventional oil contains a broader range of liquid sources comprising oil sands, extra heavy oil, gas to liquids and other liquids.

1. **Oil sands**

Heavy oil and bituminous sands are available worldwide seen in Fig. 8.2. Oil sands usually comprise of extra heavy oil or crude bitumen trapped in an unconsolidated sandstone formation. Such petroleum is forms of crude oil which are very dense and viscous at room temperature making extraction process challenging. Occasionally, the density of the heavy crude oils close or even above water density. Accordingly, this crude seldom produced by applying conventional approaches. The major modification needs to be made on the production system to handle the production process. This type of crude oils contains heavy metals and sulphur at high concentrations level, which affect the refining processes. Such type of unconventional oil does existing in Canada's and Venezuela (Bergerson and Keith 2006).

To extracting a large amount of oil from oil sands will be difficult as the production process need high capital cost, manpower, and landscape along with the source of restricted energy for production systems such as heat and power generation (Gardiner 2009).

2. **Tight Oil**

Tight oil, comprising of light tight oil is crude oil existing in hydrocarbon bearing formations that have low permeability, normally tight sandstone or shale (Mills 2008). To improve the production performance from tight oil formations the process needs hydraulic fracturing. Commonly, oil shale is shale rich in kerogen, or synthetic oil extracted from oil shales (World Energy Resources 2013).

3. **Oil Shale**

Oil shale is sedimentary rock rich with large amounts of kerogen from see Fig. 8.3. The kerogen in oil shale can be transformed into shale oil by the chemical processes

Fig. 8.2 Oil sand (Alberta, Canada). *Source* https://www.strausscenter.org/energy-and-security/tar-sands.html

Fig. 8.3 An outcrop of oil shale. *Source* Smith et al. (2007)

such as hydrogenation, pyrolysis, or thermal dissolution. The temperature when decomposition of oil shale happens, at 300 °C, rely on the time scale of the pyrolysis, however, it can occur more rapidly at higher temperatures (480 °C). The ratio of shale gas to shale oil subject on the distillation temperature and as a rule, the ratio rises as temperature increase. This process is reliant on the properties of oil shale and the processing technology used. In 2016 the World Energy Council estimated the total global shale oil resources are about 6.05 trillion barrels (World Energy Council 2016).

4. **Tight Gas**

Tight gas its gas located in hard and impermeable formations. Besides, tight gas can be located in sandstone or limestone reservoirs which are nonporous, also identified as tight sand. The production process of tight gas needs more work to extract it from the tight reservoir. This means that the pores in the reservoir rock are either irregularly scattered or poorly connected with too thin capillaries, low permeability, or the capability of the gas to mobile over the rock. The secondary recovery process, such as fracturing and acidizing, is required to produce more gas from a tight reservoir at a highly economical production rate. Typically, tight gas reservoirs are discovered in Palaeozoic formations and because of cementation, compaction, and recrystallization of the formation, the permeability was extremely decreased which can be measured in the millidarcy or microdarcy range (Dan 2008).

5. **Shale Gas**

Shale gas is natural gas (mainly methane) that is located within shale reservoirs. As shales normally have extremely low permeability to produce gas at a high flow rate, shales are not commercial sources. The risk of discovering shale gas is low in resource plays, also the possible profits per successful well are lower. Since shale has small matrix permeability, the shale formation needs fractures to add more permeability either natural fractures or apply advanced technology to generate hydraulic fracturing to make widespread artificial fractures around the wellbore. Commonly, horizontal wells are used with horizontal lengths exceed 3500 m, to increase the production area at the wellbore (Dan 2008).

Shale formations that contain profitable amounts of gas have some common properties. They are rich in organic material (0.5–25%), and are mature hydrocarbon source rocks, where heat and pressure have transformed hydrocarbons to natural gas. Shale is sufficiently hard enough to keep open fractures (US Department of Energy 2009).

6. **Gas Hydrates**

Gas hydrates are crystalline water-based solids formed of water and gas molecules. It looks like ice but it comprises massive quantities of methane. It's available everywhere around the world, and it occurs in marine sediments right beneath the sea floor and in association with permafrost in the Arctic. The gas hydrate layer extends into the seafloor where temperature goes above gas hydrate stability, typically some 10–100 m under the seafloor (Sloan 1990). Normally, hydrocarbons and freons will form hydrates at specific temperatures and pressures. The gas hydrates are massive energy resource; however, the extraction technique has up to now proven elusive. Hydrates create difficulties for the oil and gas industry because they blockage gas pipelines depicted in Fig. 8.4.

7. **Coal-Bed Methane**

Coalbed methane (CBM) is a natural gas produced from coal beds. Recently, CBM becomes the main source of energy in the producer countries. Normally, methane adsorbed into the coal matrix. Commonly It is named 'sweet gas' due to lack of hydrogen sulfide. CBM is different from any conventional gas reservoir since the methane is trapped within the coal by adsorption process. Usually, methane is close to liquid state, stored inside pores of the coal matrix. Also, the open fractures in the CBM can store free gas or saturated with water. CBM holds a little heavier hydrocarbon such as propane or butane, but no gas condensate. CBM naturally contains a few amounts of carbon dioxide. The CBM reservoirs are defined as a dual porosity reservoir in which porosity related to fractures are in charge of flow performance and the matrix porosity controls the gas storage. The range of CMB porosity can vary from 10 to 20%, but, the fracture porosity is within the range of 0.1–1% (Clarkson 2013). As mentioned early, the fracture permeability plays the major role of flow performance of CBM formation. Where, CMB permeability is within the range of 0.1–50 milliDarcys (McKee et al. 1988).

Fig. 8.4 Hydrate Plug Formed in a Subsea Hydrocarbon Pipeline. *Source* Irmann (2013)

8. **Bitumen**

Bitumen is petroleum that presents in semi-solid or solid stage in the reservoir. It usually holds sulfur, metals, and other non-hydrocarbons contents. Usually, the Bitumen density is below 10 °API and viscosity is bigger than 10,000 cP (at reservoir temperature and atmospheric pressure on a gas-free basis). To extract Bitumen at commercial amounts needs improved applications and developed recovery approaches such as steam injection. Commonly, Near-surface bitumen deposits can be extracted through mining techniques. This type of petroleum needs refining with light hydrocarbons prior to export (Dusseault et al. 2008).

8.6 Nanopore System Reservoirs

Commonly, unconventional formations are mainly nanoscale pore throat structures. The following are the ranges of the pore throat diameter for unconventional formations which are measured in nanoscale:

- Shale gas from 5 to 200 nm
- Shale oil from 30 to 400 nm
- Tight limestone oil from 40 to 500 nm
- Tight sandstone oil from 50 to 900 nm
- Tight sandstone gas from 40 to 700 nm

In the pore throats, there are substantial viscous and molecular forces. Hydrocarbon is adsorbed on the minerals surfaces or kerogens in an adsorbed state or inside solid organisms in a diffused state see Fig. 8.5. Differential pressure and diffusion are the main drivers of hydrocarbon movement and accumulation. Pore connectivity is used to characterize the flow capacity (Curtis et al. 2011).

8.7 Formation Evaluation and Reservoir Characterization of Unconventional Reservoirs

Usually, gas or oil shale formations are known as unconventional resources formations, which are very complex in terms of depositional environment descriptions and petrophysical interpretations. Such reservoirs need to be hydraulically fractured to extract a high rate of gas or oil at economic amounts. Besides, High technology is required for increasing the production performance of these reservoirs by using horizontal laterals.

The most of clay matrix particle size available in these unconventional rock reservoirs includes many heterogeneous structural components. These reservoirs contain complex pore throat structures that are mostly nanoscale pores (Loucks et al. 2012). To produce oil and gas, the formation must show very high oil and gas saturations

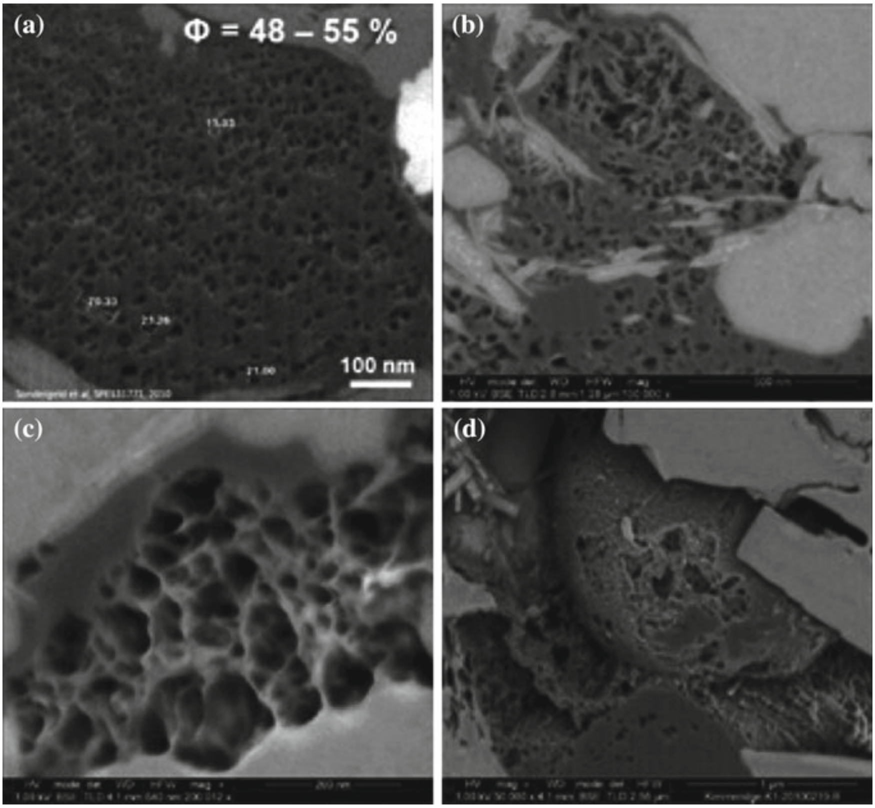

Fig. 8.5 Nanoscale Kerogen organic porosity. *Source* Curtis et al. (2011)

with very low water saturation. Commonly, the permeability is very low and usually, it's measured in the nanodarcy scale which is very complex and challengeable for formation evaluation. Fractures can occur naturally, and distributed either vertically or horizontally. Mobile hydrocarbons can exist within the pores and also existing as absorbed hydrocarbons to the clay and kerogen surfaces. Generally, acquiring high technical data from different sources is essential to have better formation evaluation of reservoir characterization.

1. **Rock Composition Quantification**

The quantification of the mineral composition and lithology of the Reservoir is the first stage to understand the characterization of unconventional reservoirs. Where, the mineral composition is the main important property that has an influence on the productivity of the reservoir (Walles and Cameron 2009). Term shale is normally used to describe very fine-grained deposited rocks composed of clay grains with some silt. Typically, the grain size is alike in most shale reservoirs, mineralogy differs considerably, both vertically and horizontally inside a single shale reservoir and between shale reservoirs. The formation could have varying amounts of minerals such as quartz, feldspars, dolomite, and clay. Where, the variations in reservoir mineralogy are related to the variations in the mechanical properties of the reservoir rock. The obtained data from wireline, logging while drilling Lithology, core study, and mud log can be utilized to quantify the lithology and mineral composition of the reservoir. Correct lithology and mineralogy interpretations permit more accurate porosity estimation that can help to make accurate stimulation and completion design.

2. **Total Organic Carbon Quantification**

The best clear characteristic of a source rock is that it holds a high quantity of total organic carbon (TOC). TOC has 3 main components, gas or oil, kerogen, and residual carbon (Jarvie 1991). Naturally, the hydrocarbon is generated from kerogen at high temperature and pressure. Normally, in source rock some of the hydrocarbons migrated into reservoir rock to become conventional reservoirs, however, in unconventional shale reservoirs a significant amount of the hydrocarbon is not migrated and in this case, the source rock becomes a reservoir. Several physical characteristics about the TOC and kerogen need be to quantified (Passey et al. 2010).

3. **Porosity and Permeability Quantification**

As Discussed early, shale reservoirs hold complex pore throat structures composed of very small interparticle and intraparticle. Besides, natural fractures are exists and distributed vertically and horizontally in the reservoir (Loucks et al. 2012). Conventional laboratory approaches for porosity and permeability determination are inappropriate in shale reservoirs. Typically, total shale porosities are low (5–12%). The variable amount of TOC and inorganic mineral components in the reservoir will make the determination of shale porosity by using conventional log technology very difficult. By using elemental spectroscopy and nuclear magnetic resonance logging equipment can improve accuracy. Porosity must be measured from the core and verified with the log derived porosities. Numerous laboratory approaches are used for porosity such as include mercury injection capillary pressure (MICP), gas research institute technique (GRI) standard crushed porosity, and scanning electron microscopy (SEM), and focused ion beam (FIB) tomography depicted in Fig. 8.6. Shale Permeability is very low, and measured in the nanodarcy scale and must be measured in the laboratory using core analysis measurements and calibrated with core responses. Typical laboratory approaches applied to obtain shale permeability include pressure decay, pressure pulse decay, and MICP (Passey et al. 2010).

4. **Fluid Saturation Quantification**

In conventional reservoirs, hydrocarbons are stored only in the pores of the matrix. The hydrocarbon saturations are calculated from laboratory analyses or from the wireline or LWD log measurements of resistivity and porosity. Usually, in unconventional reservoirs, hydrocarbons are trapped as free oil and gas in the fractures and shale matrix pores. Also, the sorbed gas and oil either adsorbed to the kerogen

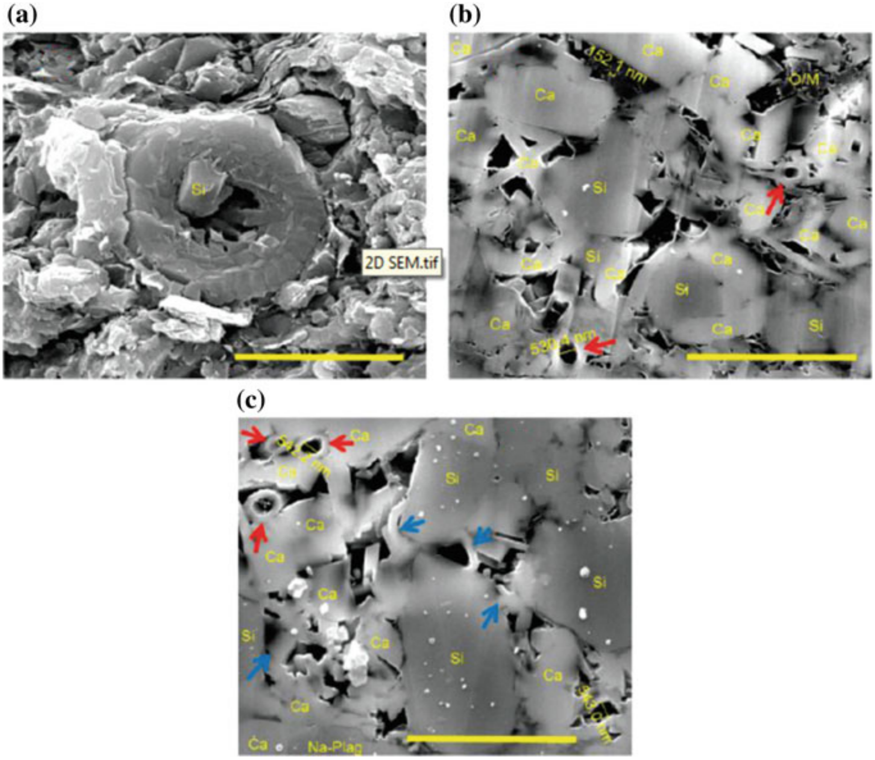

Fig. 8.6 Differences in a resolution of the grain-related, organic matter and pore types and distribution that can be identified from ion milled SEM samples (**b**, **c**) compared to a standard SEM image. *Source* Driskill et al. (2013)

and mineral surfaces inside the fractures or absorbed to the kerogen and mineral surfaces inside the matrix rock. The dissolved gas can be stored also in the hydrocarbon liquids existing in the bitumen.

In unconventional reservoirs, a mixture of laboratory studies is the primary technique applied to determine volumes and saturation of gas or oil. For crushed core samples, Wise Retort or Dean-Stark analysis are applied to determine fluid saturations. Adsorption and desorption isotherm studies are used in gas shale reservoirs to estimate adsorbed gas volumes and total gas volumes (Bustin et al. 2009). Normally, water saturation is determined by applying the same methodology and techniques used for conventional reservoirs, such as resistivity and porosity log using a shaly sand equation or Archie equation. Adequate core saturation measurement needs to be used to compare with log derived fluid saturations.

8.8 Determination of Kerogen Contained Fluid Saturations

Comprehending the nature of storage and transporting the hydrocarbon in unconventional reservoirs, still under investigation. In free and gas adsorbed system, already taking into account the nanoscale porosity and non-darcy flow systems, with varieties of pore throats scale, together with dispersion methods. It's very important to develop unconventional models for molecularly dynamic kerogen adsorption surfaces with variable adsorption volumes for hydrocarbons. Researchers have developed the concept of understanding free and adsorbed hydrocarbon components through developing model methodologies comprising CBM molecular dispersion model(s) methods for gas quantification by desorption and adsorption studies (Xu et al. 2012). Hydrocarbon liquid-rich mudrock resource plays are currently the least understood with respect to these complex transport mechanisms and adsorption systems. Existing methods (Shabro et al. 2012) include developing novel numerical algorithms that concurrently considered gas dispersion in kerogen, slip flow, Knudson diffusion, and Langmuir desorption.

1. **Langmuir Isotherm Formulation**

The relief of adsorbed gas is usually defined by a pressure relationship known as "Langmuir Isotherm". The Langmuir adsorption isotherm proposed that the gas adheres to the surface of the shale or coal, and covers the surface as a single layer of gas (Fekete Associates 2012).

The typical formulation of Langmuir isotherm is (Eq. 8.1):

$$\mathrm{C_{gi}} = \frac{\mathrm{V_L} * P}{P_L + P} \tag{8.1}$$

where $\mathrm{V_L}$ is Langmuir volume; $\mathrm{p_L}$ is Langmuir pressure; p is gas pressure; $\mathrm{C_{gi}}$ is adsorbed gas content per unit mass of shale. $\mathrm{P_L}$ and $\mathrm{V_L}$ are indispensable parameters to describe the adsorption, which can be obtained by isothermal adsorption experiments.

The Eq. 8.1 applied for pure coal/shale. For application to coalbed methane reservoirs, Eq. 8.2 below is modified to consider ash and moisture content of the coal.

$$V(P) = (1 - \mathrm{C_a} - \mathrm{C_w})\frac{\mathrm{V_L} * P}{P_L + P} \tag{8.2}$$

where, $\mathrm{C_a}$ is ash content of the coal, scf/ton; $\mathrm{C_w}$ is moisture content of the coal, scf/ton.

2. **Free Gas and Adsorbed Gas Equations in Shale reservoirs**

Unconventional hydrocarbon accumulation analysis is a method that applied based on geological observations and information to calculate original oil and gas in place. The approach used to estimate the dynamic contributions of free and adsorbed gas (Eq. 8.3) in shale gas production (Fekete Associates 2012).

$$V(OGIP) = (\mathrm{V}_{\text{free}} + \mathrm{V}_{adsorbed}) \quad (8.3)$$

2.1 Adsorbed Gas Equations

Usually, shale gas formations hold adsorbed gas more than free gas. So, oil initial in place (OGIP) estimations for shale formations must also account for adsorption. The following equations can be applied to estimate the Original Adsorbed Gas-in-Place (OGIP) (Eq. 8.4) for shale gas reservoirs (Fekete Associates 2012).

$$OGIP = 43{,}560 * A * h * \rho_b * \frac{V_L * P}{P_L + P} \quad (8.4)$$

where h is thickness, ft; A is the area, acres; $\boldsymbol{\rho_b}$ is adsorbed gas density, ton/ft^3.

2.2 CBM Reservoir Calculations

For coalbed methane formation, adsorbed gas is the most significant influence factor when estimating OGIP (Eq. 8.5). Normally, free gas accounts as a small amount of the entire gas-in-place. Typically, the used approach to estimate the adsorbed gas in coalbed methane is similar to that for shale gas, only a few additional parameters are included (Fekete Associates 2012).

$$OGIP = 43{,}560 * A * h * \rho_b * C_{gi} * (1 - C_a - C_w) \quad (8.5)$$

where:

C_{gi} is gas content measured in coal or shale, scf/ton.

2.3 Free Gas Equations

Free gas equation is the same for all gas reservoirs (Eq. 8.6)

$$OGIP = 43{,}560 * A * h * \emptyset * \left(S_{gi}\right) * \frac{1}{B_{gi}} \quad (8.6)$$

where, S_{gi} is gas saturation, %; B_{gi} is gas formation Volume Factor, ft^3/scf; Ø is porosity, %.

8.9 Factors Affecting Unconventional Oil and Gas Recovery

Unconventional Oil and Gas (UOG) reservoirs normally spread across large areas and therefore represent very large hydrocarbons in place. But, even by using very developed unconventional technologies, the recovery factor still very low, Typically, 10% or less for liquid-rich shales and 25–35% for gas-rich shales (Energy Information Administration 2013). Furthermore, because the recovery is greatly reliant on the technology used, per-well production is not carefully determined from geologic evidence such as in conventional reservoirs. Instead, production is extremely sensitive to the effectiveness of the stimulation process and in situ reservoir conditions. Assessment of unconventional oil and gas production, mainly in shale formations, is more complex because the reservoir engineering models and approaches work very well for nanoscale formations (Javadpour et al. 2007). Besides, the nature, efficacy, and possible environmental influences of unconventional oil and gas development will vary considerably among and within unconventional oil and gas resource regions because of geographical, geological, and operational changeability (GAO 2012).

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