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Characteristics of Unconventional Oil and Gas Resources

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Chapter 3:
Characteristics of Unconventional Oil and Gas Resources

"The pessimist complains about the wind. The optimist expects it to change. The leader adjusts the sails."

John Maxwell

Foreword

The adjustments to the unconventional resource exploitation and development sail starts here.

Chapter 2 discussed the difference between unconventional resources and conventional resources. Here, discussions are presented to characterize unconventional oil and gas resources. We start the discussion by reviewing the unconventional resources in general, followed by addressing the unconventional resource triangle, which then leads us to discuss the shale resources. This is followed by an overview of tight oil and gas and coalbed methane (also referred to as coal seam gas, or CSG, in Australia).

3.1   Introduction to Unconventional Resources

Some definitions change with time. The depths that correspond to deep water for oil and gas have increased over time as technologies and capabilities have been enhanced. Similarly, the definition of tight oil has changed, as has the meaning of unconventional in relation to reservoirs. For our purposes, we often describe reservoirs as shales, when they may be, in fact, a combination of marls, mudstones, or even carbonates. This chapter presumes the reader has some familiarity with both conventional and tight oil and gas principles as we discuss unconventional reservoirs. For this purpose we can use practical and approximate definitions based on the types of wells and completions required.

- Conventional reservoirs can be developed with vertical wells and do not need large hydraulic fracture stimulation treatments. If used, a conventional well's hydraulic fracturing treatment is typically less than a 100-ft. wing length and has a cost that is less than 10% of total well costs. Using horizontal wells in conventional reservoirs may significantly improve performance if the reservoir is

naturally fractured, is thin, or has important gravity features such as a gas-oil or water-hydrocarbon contact. Transient flow behavior in such wells is often a practical approach for characterizing the reservoir.

- Tight reservoirs require large hydraulic fracture stimulation treatments whose half-wing length is hundreds of feet, which can cost a significant portion of total well costs. Tight reservoirs produce at negligible to uneconomical rates without stimulation. Horizontal wells with multiple hydraulic fracture stages may improve production; however, operators rarely use dozens of such stages in typical tight reservoirs. Transient flow periods in such wells may be over many months.

- Unconventional reservoirs require long (3,000 to 10,000 ft.) horizontal wells with dozens of hydraulic fracture stages for commercial production. The proximity of the fracture stages results in stress interference and some degree of improvement in the aggregate matrix permeability. This arises from multiple mechanisms that can include slippage of critically stressed fractures, movement along slowly slipping faults, and complex hydraulic fracture geometry. Transient flow behavior in such wells is highly complex. Diffusion may ultimately be an important contributor to production.

3.1.1   Shale Reservoirs as Unconventional Plays

According to the US Geological Survey, production from unconventional reservoirs exists in geographically extensive accumulations (USGS report). Unconventional reservoir deposits generally lack well-defined hydrocarbon/water contacts and include coalbed methane, some tight sandstone reservoirs, chalks, and self-sourced oil and gas in shale accumulations. The assessment methodology and production practices for unconventional reservoirs vary from those used for conventional resources. General categories of unconventional petroleum include:

- Deep gas
- Shallow biogenic gas
- Heavy oil and/or natural bitumen
- Shale gas and oil
- Gas hydrates
- Coalbed methane

While the level of maturity of these unconventional resources varies, oil and gas production from shale reservoirs is growing at a phenomenal rate. The type of shale production being discussed is generally conventional oil or gas produced from relatively deeply buried shales that are produced in a manner

roughly similar to conventional wells. We refer to this as shale oil and shale gas. The term *oil shale* is widely applied to petroleum extracted from shallow rocks with very high kerogen content. Many of the rocks referred to as oil shales are not shales and theses rocks are often physically mined rather than having the hydrocarbons produced through wellbores. Oil shales typically contain solid or ultraviscous hydrocarbon material in their pores. While some oil shales can be burned directly, most require some sort of extractive process, coupled with upgrading, to yield oil like hydrocarbons. Oil shales are not discussed in this book.

3.1.2   So, What Is a Shale Anyway?

Shales are the most abundant types and volumes of rocks in sedimentary basins worldwide. Shales are the most abundant sources of hydrocarbons for oil and gas fields and due to their low permeabilities form the hydrocarbon seal for many fields. A conventional oil or gas field needs a source, a reservoir (usually porous sandstones or carbonates such as limestone or dolomite), a trap (such as a structural closure, sealing fault, or pinchout), and a seal. The source is necessary for hydrocarbons to exist and some pathway is necessary for these hydrocarbons to migrate. The reservoir porosity was usually water filled at the time of deposition, allowing the hydrocarbons to migrate through the porosity due to having lower density than the water. The trap and seal are necessary to prevent continued migration (to keep the hydrocarbons in place) and to allow the reservoir to accumulate and store oil or gas. As a result, geologists and geochemists have studied shales extensively with most of their historical effort focused on shale's source rock potential. The fact that many shales still contain significant amounts of natural gas is no surprise to drillers and geologists. It is routine to observe natural gas "shows" while drilling through shales, occasionally in significant volumes. But while it may be clear to most readers what porous sandstone or carbonate rock is like (the rocks that form most oil and gas reservoirs), shales remain somewhat of a mystery.

There are multiple definitions of what constitutes shale. A geologist once mentioned that the way to differentiate between siltstone and shale was to put it in your mouth. If it tastes gritty, it is a siltstone. If it tastes smooth or oily, it is shale. For the record, the authors do not recommend putting any rocks in your mouth!

Shales are sedimentary rocks composed of clastics (portions of older rocks) comprised of silts, muds, and clays. Geological definitions of shales typically reference their grain size as being clay-like (less than 1/256th mm diameter particles).

Silts are also defined based on grain sizes (between 1/16th and 1/256th mm) and are positioned between clays and sands. Very fine silts can be primarily composed of quartzitic materials that are lacking in typical clay minerals. Clay minerals often include kaolinite, montmorillonite-smectite, illite, and chlorite. There are dozens of pure clays, with most clays being mixtures of multiple pure clays. One important clay type in oilfield operations is bentonite, a typical weighting component of drilling mud. Another physical property often used in defining shales is their tendency to split into thin sheets or slabs (fissility). Muds are simply mixtures of water and very fine silt, clay, and soil particles. Mudstones are hardened muds that may not show fissility unless desiccated. While most shales are clastics, significant carbonate components can be present in shales. The formations we refer to as *shale gas* or *shale oil plays* are often layers of shales and layers of silts and/or carbonates.

The depositional environment of shales that are resource plays is typically a low-energy one that allows very fine-grained particles that will constitute future shales to be deposited. High-energy deposits such as channel sands and turbidites will also lead to shale deposition. The low depositional environments associated with marine shales means that their geological and petrophysical properties change relatively slowly over large distances compared with the higher levels of heterogeneities in many sandstones and carbonates. Petrophysicists take advantage of this when analyzing logs of varying vintages and from varying suppliers by normalizing log responses in marine shales.

Very fine-grained, organic material (usually from plant materials) is often deposited concurrently with the silt, mud, and clay matter that will eventually form shales. Total organic carbon (TOC) is the weight-percent of organic carbon in the shale (and does not include carbon from carbonates for example). Because many shales have relatively high organic carbon content, under certain heat and temperature conditions, shales can serve as source rocks for oil and gas reservoirs. The organic content originated with living material, ultimately from plant, animal, and bacterial matter such as algae, plankton, or decomposed plant materials. After death, the materials decompose, and the decomposition products can form new polymers to form kerogen. Diagenesis is controlled primarily by biological and chemical activity associated with mineralogy and redox conditions. Complex thermal transformations characterize subsequent kerogen transformation.

The word kerogen was originated by Professor Crum Brown (of the University of Edinburgh, Scotland) and referred specifically "…to the carbonaceous matter in shale that gives rise to crude oil in distillation" (Brown 1979). Kerogen now refers more broadly to all of the solid organic material in sedimentary rocks; kerogen is generally insoluble in water or organic solvents due to their high molecular weights. Bitumen refers to the insoluble portion.

Kerogen may be formed under various circumstances from this organic matter, which can be broken down into lighter organic materials under heat and pressure. Most oil and gas produced originated with such shales as sources with a few exceptions.

Shales generally have extremely low permeability due to their very fine grain size. Permeabilities are so low in most shales that excellent seals for oil and gas fields can be formed by shales. Drillers and mud loggers have long known that many shales contain significant quantities of natural gas, because natural gas discoveries are commonplace during drilling through shales. While some shales are rich in heavy hydrocarbons (oil shales), this discussion focuses on shales that are likely to contain natural gas or oil.

It is important to note that the type of shale production being discussed here is generally conventional oils or gas produced from relatively deeply buried shales that are produced in a manner roughly similar to conventional wells. We refer to this as shale oil and shale gas. The term *oil shale* is widely applied to petroleum extracted from shallow rocks with very high kerogen content. Many of the rocks referred to as oil shales are not actually shales—these rocks are often physically mined rather than having the hydrocarbons produced through wellbores. Oil shales contain typically solid or ultraviscous hydrocarbon material in their pores. While some oil shales can be burned directly, most require some sort of extractive process coupled with upgrading to yield oil like hydrocarbons. Oil shales are not discussed here.

Shale gas production has been recorded for over a century in the Devonian age formations in the Appalachian basin. More than 20,000 wells have been drilled in these shallow shales. Older (and deeper) Devonian shales include the Marcellus formation, which is now a major focal point for the application of advanced technology. Because we have known about these shales and their hydrocarbon potential for decades, if not more than a century, why has it taken so long to produce them? The answer is clear: the technology to drill, evaluate, complete, and produce these shale plays has only been available for a decade (at best), and many advances have been made in just the last few years.

3.1.3   Shales as Resource Plays

A resource play is a relatively large hydrocarbon accumulation that occurs over a broad geological area. In a resource play, the geological risk of encountering the hydrocarbon bearing strata is nearly certain within the play area. A resource play may nonetheless have wide variability in well performance; however it is often the case that such variability cannot easily be predicted in advance or even correlated to conventional measurements (e.g., porosity, thickness). Resource plays have alternately been described as statistical plays, in which an operator must drill a large number of wells and can expect fairly repeatable results if enough wells are drilled.

Tier one criteria used in defining resource plays include the following characteristics taken from the Society of Petroleum Evaluation Engineers (SPEE) Monograph 2011:

1. Exhibits a repeatable statistical distribution of estimated ultimate recoveries (EURs).

2. Offset well performance is not a reliable predictor of undeveloped location performance.

3. Continuous hydrocarbon system that is regional in extent.

4. Free hydrocarbons (non-sorbed) are not held in place by hydrodynamics.

The SPEE provides certain statistical guidelines for the evaluation of resource plays that require each of the prior criteria to be met. Many shale gas reservoirs are considered to be resource plays, with both geological and engineering data supporting the criteria. It cannot be proven that a given area is a resource play until a significant number of wells have been drilled—and enough performance data is analyzed—to justify the conclusion. From those criteria, the most important criterion is the first one, which is the repeatable statistical distribution of EURs. Having a statistical distribution of EURs is characteristic of many reservoirs. If the mean measurement (and other measures of the statistical distributions) varies significantly spatially, especially if the variance is, in some way, correlated to readily identifiable geological data (such as TOCs, thickness, etc.), the play is unlikely to be a true resource play.

The second criterion implies heterogeneity in well performance. This is true of many non-resource plays, including many carbonate reservoirs, so it is not sufficient. The importance is that reasonably obtainable measurements (such as kh) do not predict well performance changes. This truly complicates matters when operators assume the second

criterion is "true" and decide not to go to the expense of obtaining well logs. As we will see in Chapter 8, formation evaluation tools for shale gas wells are available that can produce detailed geological and mineralogical information including clay types, TOC, silica content, etc. Such data might be highly predictive of well performance and could even indicate ways to improve well completions and future drill site selections. If such logs are not run and analyzed, the operator will conclude that there is no way to explain variability other than the "statistical" nature of the play.

The third and fourth criteria are generally present in all productive shale gas plays. Tier two criteria (the next tier of criteria) include:

5. Requires extensive stimulation to produce at economic rates.

6. Produces little in-situ water (except for coalbed methane and tight oil reservoirs).

7. Does not exhibit an obvious seal or trap.

8. Low permeability (< 0.1 md) shale bulk permeabilities are typically less than 0.001 md.

Shale gas plays generally satisfy each of these criteria easily. As the plays form seals for conventional reservoirs, they do not have to have a separate trap. Thus, a syncline may easily be as productive as an anticline in shale. The permeabilities of shale gas reservoirs are often well below 0.01 md and generally require stimulation. Shale gas reservoirs have such low permeabilities that free water production is rare; highly fractured shales could allow water from deeper zones to be produced.

3.1.4   Shale as Reservoirs?

While shales are known to be the principal sources for conventional hydrocarbon plays as well as seals, shales can also be the reservoir and trap. Most of the gas created in such reservoirs would be thermogenic in origin, although some shales (e.g., the Antrim) have significant quantities of biogenic gas. Gas is stored in shales either as free gas in the pore spaces or adsorbed onto the organic material or surface walls in the shale.

Thermogenic methane was formed when organic matter was compressed at very high pressures for a very long time. Just as in oil formation, thermogenic methane is a cracking process that transforms organic particles carried in the clastic material, which then forms the origin of shales. The nature of the organic material and time and pressure dictate what is formed

in thermogenic processes. Thermogenic gas can contain significant quantities of heavier hydrocarbons.

Biogenic methane can be formed by microorganisms that chemically break down organic matter. Biogenic methane is generally formed at shallow depths in anoxic environments. While most of this methane escapes to the atmosphere, some can be trapped and buried at depth. Modern landfills can also form biogenic methane. Biogenic methane is essentially unrelated to the processes that form oil—biogenic gas primarily contains methane with very few heavier hydrocarbons. A standard measure of whether a gas is thermogenic or biogenic can be determined by gas geochemistry. Thermogenic gas has less carbon 13 compared to the predominant carbon 12 than do biogenic gases.

3.1.5   Role of Geochemistry

Many tools are used to analyze and study shales. The total organic carbon (TOC) is typically determined by calculating the difference between total organic carbon and the carbonate carbon concentration. While both of the latter measurements are generally made with cuttings or core samples, petrophysical estimates of TOC can provide excellent and continuous estimates of TOC.

Pyrolysis of organic matter in shales involves heating samples to extract volatile hydrocarbons (referred to as S1), thermogenic hydrocarbons (S2), and the carbon dioxide released up to a fixed temperature (S3). The methodology to make these measurements involves pulverizing a small sample of rock and heating it to increasing temperatures. These values (S1 through S3) are used in calculating several common geochemical values including the hydrogen and oxygen indices (HI and OI). The temperature above which no further hydrocarbons are released by pyrolysis is referred to as T_{max} and provides a common measure of organic matter. The indices are defined as follows:

$$HI = (100S\_2)/TOC$$

with units of milligrams hydrocarbons per gram of organic carbon and

$$OI = (100S\_3)/TOC$$

with units of milligrams CO_2/gram organic carbon.

Geochemists use these values to assess the shale's source rock potential along with the hydrocarbon generation potential and also to describe the types of kerogen. The authors of Chapter

8 point out the value of the S_1/TOC ratio and demonstrate that values in excess of 100 milligrams hydrocarbons/gram of organic carbon are very positive for the production potential of shale oil and shale gas.

Vitrinite reflectance is another widely used measurement associated with shales. Plants take in CO_2 and water to generate carbohydrates and polymers that form plant material such as cellulose and lignins. It is this plant material that (with time, temperature, and pressure) ultimately creates oil or natural gas. Vitrinite is a shiny material formed by the thermal alteration of such organic matter; it is present in most kerogens and coals. Vitrinite reflectance is often used to describe the maturity of coals. For example, lignite is a coal with low thermal maturity and reflectance, and anthracite is a highly reflective and more mature coal. Coalification of peat is strongly analogous chemically and physically to the maturation of kerogen. Vitrinite reflectance can be used in conjunction with TOC values, pyrolysis data, etc. Vitrinite reflectivity is typically measured with an oil-immersion microscope and a device for measuring reflected light. Comparisons are made with reference standards to define the reflectance in oil, R_0. While R_0 is a measure of thermal maturity, its significance is a function of the type of kerogen being analyzed. Nonetheless, low values of R_0 indicate immature kerogen. As R_0 increases, the indicated maturity levels suggest oil generation, gas generation with condensates (wet gases), and, ultimately, dry gases at high levels of thermal maturity. At such levels, sufficient time and temperature will have cracked heavier organic molecules.

Different types of kerogen are usually described based on their relative amounts of hydrogen, carbon, and oxygen. Each type of kerogen has varying tendencies to form oil, gas, and coal. The reasons for the different chemical compositions include the type of organic material present (including plankton, algae, spores, pollen, diatoms, etc.) and the chemical processes to which the material was exposed.

While not as routinely used in shale oil and shale gas evaluations, geoscientists often make use of the organic carbon isotope ratios, and atomic carbon nitrogen ratios, to analyze shale depositional histories and in related studies. Geochemistry can be a powerful tool for reservoir engineers in many areas besides the analysis of unconventional reservoirs.

3.2   Workflow to Address Unconventional Resource Development

As we have noted, classical unconventional resource definitions include coalbed methane (CBM), tight oil and gas reservoirs, and shale oil and gas. Sometimes heavy oil development is lumped with unconventional resources. We choose to place heavy oil in a different category, because the others, as a group, have a lot of similarity in the technology and development requirements that heavy oil does not.

Cost-effective development of the three unconventional resources (listed previously) can follow a certain life-cycle approach, which is a six-step, phased approach that addresses exploration, appraisal, development, production, rejuvenation, and abandonment phases. In the life-cycle approach, we acknowledge the subtle differences between the three groups of unconventional resources and how these factors affect the overall understanding of the reservoir. From this, we can extrapolate the exploitation strategy (placement of wells and stimulation locations and all aspects associated with the process followed by a rejuvenation phase). Field case studies suggest that using such a process can positively affect the recovery factor, while the increased operational efficiency garnered from the process can reduce cost, depending on the scale and scope of the project. Finally, well-thought-out field understanding and development design alone is not good enough without a continued commitment of resources (people, tools, and software). Of these resource commitments, typically the hardest one to meet is securing the proper unconventional resources expertise. Over the last decade, an increased understanding about unconventional resource development has come about in North America, which is now prime to be potentially disseminated as long as we take the time to understand the difference of the new basin and its associated challenges (Ahmed 2014).

There are subtle differences between the three unconventional resources, even though they still follow a similar workflow process as illustrated in **Fig. 3.1** (an entire chapter on workflow is dedicated within Chapter 5). Therefore, as we illustrate the resource triangle, we will then follow with a detailed characterization of the shale oil and gas. Then, we dedicate sections to tight oil and gas and CBM to illustrate the subtle differences in the characterization of both, even though the workflow and development process remain unchanged.
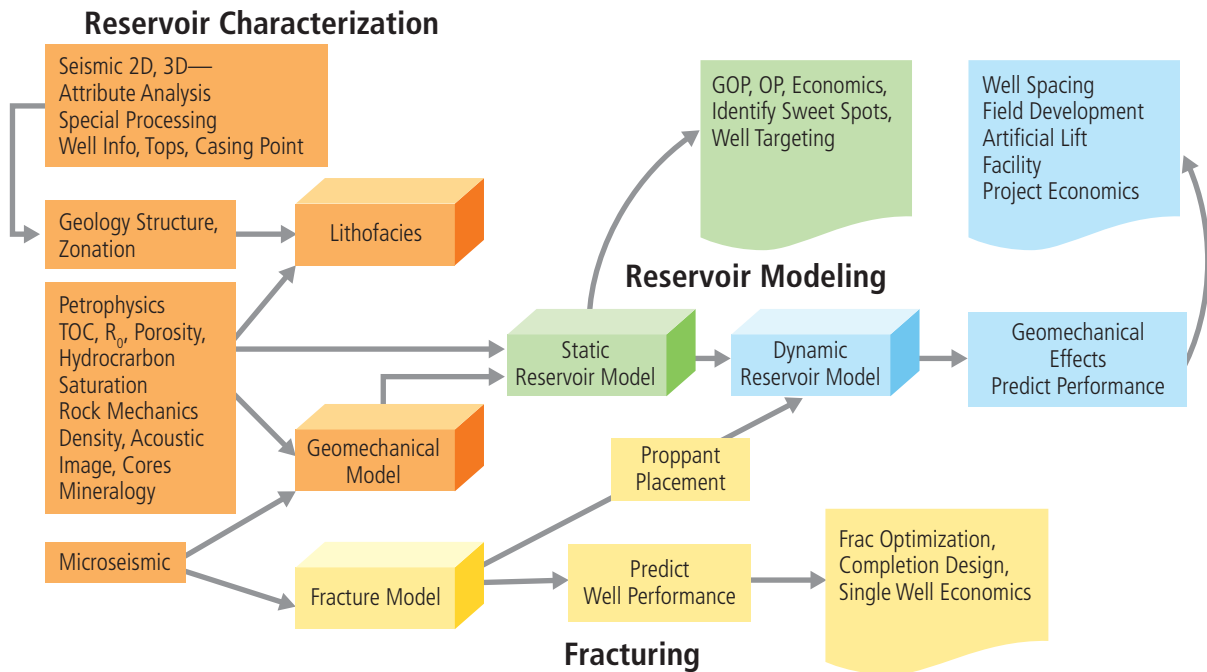
Fig. 3.1—Workflow process and outline for unconventional resources exploitation and development. (From Vassilellis et al. 2011.)

3.3   The Unconventional Resource Triangle

The resource triangle concept was used by Masters (1979) as a method to find large gas fields and build a company in the 1970s. **Fig. 3.2** illustrates the principle of the resource triangle. In the resource triangle, conventional gas is located at the top with better reservoir characteristics and quality, is associated with conventional technology and ease of development, but exists in small volumes (Holditch 2006). As we navigate further down the triangle, past tight gas and coalbed methane (CBM), shale gas (and gas hydrates) are found at the bottom of the triangle. Progression to the bottom of the triangle is associated with permeability and reservoir quality decreasing, the technology needed to develop increasing (i.e., becoming more complex), and difficulty of development increasing; however large volumes of these resources can be found. The concept of the resource triangle applies to every hydrocarbon-producing basin in the world. Martin et al. (2008) validated the resource triangle concept using a computer program, database, and software they developed. They also expanded the resource triangle to include liquid and solid hydrocarbons adding heavy oil and oil shale, and referencing work from Gray (1977). Shale resource development is at the bottom left signifying that the resource base is huge (documented in Chapter 4) with decreasing reservoir quality requiring deployment of increasing and demanding technology.

3.4   Characteristics of Shale Oil and Gas

In addition to Section 3.1, in this section we will use the work done by others to characterize shale oil and gas as an unconventional reservoir contained in fine-grained, organic rich, sedimentary rocks, including shale, but composed of mud containing other minerals like quartz and calcite (US DOE 2009; Warlick 2010; US EIA 2011). A number of formations broadly referred to by industry as *shale*, may contain very little shale lithology and/or mineralogy, but are considered to be shale by grain size only. Passey et al. (2010) describes shale as extremely fine-grained particles, typically less than 4 microns in diameter, but that may contain variable amounts of silt-sized particles (up to 62.5 microns). No two shales are alike and they vary areally and vertically within a trend and even along horizontal wellbores (King 2010). Not only will shales vary from basin to basin, but also within the same field (Economides and Martin 2007). These reservoirs are continuous hydrocarbon accumulations that persist over very large geographic areas. Shale hydrocarbon accumulations can range from dry gas to wet gas to condensate, and to all oil phases as seen in the Eagle Ford development. The challenge in developing shale resources is not just to find oil and gas, but to also find the best areas, or sweet spots, that can result in the best production and recovery (Jenkins and Boyer 2008).
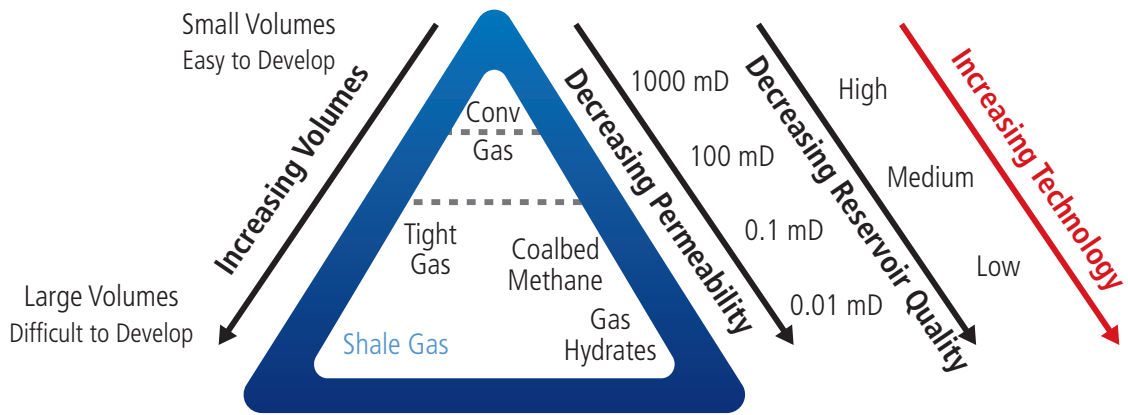
Fig. 3.2—The Unconventional Resource Triangle: The concept of the resource triangle applies to every hydrocarbon-producing basin in the world. (Holditch 2006 after Masters 1979 and Gray 1977.)

Shale reservoirs have no trap like conventional gas reservoirs, and do not contain a gas and/or water contact. Shales are the source rock, which also now acts as the reservoir, where the total or partial volume of oil and gas (hydrocarbon) remains. Shales are the source rock for most of the hydrocarbons. The key to success with shale is to find the shale plays where the remaining hydrocarbons were not expulsed and did not migrate into conventional formations and are now economically viable for development. A note of caution: not all shales are source rocks and not all shale source rocks still hold the accumulated hydrocarbon.

In terms of the flow behavior, we have already mentioned in the coalbed methane section that shale has more similarity with coalbed methane than tight sedimentary rocks and is illustrated further below.

Natural matrix permeability in shales is extremely low, often in the nano-darcy range. Measurement of shale permeability is difficult and the results are probably inaccurate. In this extreme low-permeability environment, gas (hydrocarbon) flow through the matrix is extremely limited and insufficient for commercial production. Various authors have estimated that a gas molecule will move no more than 10 to 50 feet per year through shale matrix rock. Shale porosities are also relatively low ranging from less than 5 to 12%. Shale reservoirs require hydraulic fracturing to produce commercial amounts of gas. Shale reservoirs with oil resources tend to have relatively higher permeability and porosity, yet still very low. The porosity is still fairly low; therefore, hydraulic fracturing is still required in this type of shale reservoir to create a path for the oil to flow.

A number of different reservoir parameters that are not necessarily deemed important for conventional gas are still significant for assessing economic viability, development, and well completion techniques for shale production. This includes the following parameters that we must now consider for shale reservoirs:

- Total organic carbon (TOC) content, kerogen type, and thermal maturity (also referred to as, and measured as, vitrinite reflectance, R_0)
- Mineralogy/lithology, brittleness, existence of natural fractures, and stress regime
- Multiple locations and types of oil and gas storage in the reservoir
- Thermogenic or biogenic systems
- Depositional environment, thickness, porosity, and pressure

Though not a parameter, the characteristic steep production decline profile is an important aspect here.

The discussion, next, briefly covers each of these parameters along with the unique aspects of shale, to provide an understanding of the parameters' significance in play analysis and development.

Organic materials, microorganism fossils, and plant matter provide the required carbon, oxygen, and hydrogen atoms needed to create natural gas and oil. TOC is the amount of material available to convert into hydrocarbons (depending on kerogen type) and represents a qualitative measure of source rock potential (Jarvie et al. 2007). This measure is commonly expressed as a *percent by weight*, but it is also sometimes expressed as *percent by volume* (volume % approximately twice that of weight %). Oil and gas

Table 3.1—Types of kerogen and the hydrocarbon potential by environment, type, and origin. (From Holditch 2011.)

Types of Kerogen and Their Hydrocarbon Potential				
Environment	Kerogen Type	Kerogen Form	Origin	HC Potential
Aquatic	I	Alginite	Algal bodies	Oil
			Structureless debris of algal origin	
	II	Amorphous Kerogen	Structureless planktonic material, primarily of marine origin	
		Exinite	Skins of spores and pollen, cuticles of leaves, and herbaceous plants	
Terrestrial	III	Vitrinite	Fibrous and woody plant fragments and structureless colloidal humic matter	Gas, some oil
				Mainly gas
	IV	Inertinite	Oxidized, recycled woody debris	None

source rocks typically have greater than 1.0% TOC. TOC richness can range from poor at < 1%, to fair at 1 to 2%, to good-to-excellent at 2 to 10% (PESGB 2008). TOC is not the same as kerogen content, because TOC includes both kerogen and bitumen. TOC measurements in shale are determined from wireline logs and by direct measurement from cores and drill cuttings. Kerogen is a solid mixture of organic chemical compounds that make up a portion of the organic matter in sedimentary rocks. Kerogen is insoluble in normal organic solvents because of the huge molecular weight of its component compounds. The soluble portion is known as bitumen. There are basically four types of kerogen, three of which can generate hydrocarbons. Type I generates oil, Type II wet gas, and Type III dry gas (Holditch 2011). Understanding the kerogen type helps to predict the hydrocarbon type in a play. **Table 3.1** shows the types of kerogen and their hydrocarbon generating potential.

Thermal maturity measures the degree to which a formation has been exposed to high heat needed to break down organic matter in hydrocarbons. As temperature increases with the increasing depth in the earth's crust, heat causes generation of hydrocarbons and can ultimately destroy them. Typical temperature ranges at which oil and gas are generated are shown on **Fig. 3.3**. The oil window is 60 to 175°C (140-to-350°F) and the gas window is 100 to 300°C (212 to 570°F). The position of oil and gas windows within

a basin is dependent on the type of organic matter and heating rate. Thermal maturity is a function of both time and temperature (Holditch 2011). Understanding the level of thermal maturity, or indeed whether the shale is thermally mature at all, is key to understanding shale resource
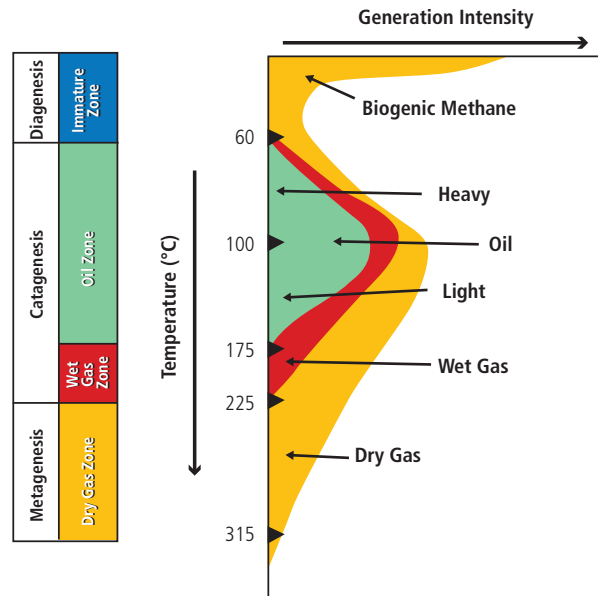

Fig. 3.3—Typical temperature range at which oil and gas are generated. (From Holditch 2011.)

potential (PESGB 2008). Also, higher thermal maturity leads to the presence of nanopores, which contribute to additional porosity in the shale matrix rock (Kuuskra et al. 2011).

Vitrinite reflectance, R_0%, the most commonly used technique for source rock thermal maturity determination, measures the intensity of the reflected light from polished vitrinite particles (a maceral group formed by lignified, higher-land plant tissues, such as leaves, stems, and roots) in shale under a reflecting microscope. Increased reflectance is caused by aromatization of kerogen and loss of hydrogen (Jarvie et al. 2007). **Fig. 3.4** is the thermal maturation scale. Dry gas occurs when R_0 is greater than 1.0%, wet gas when R_0 is between 0.5 and 1.0%, and oil when R_o is between 0.5 and 1.3% (Kuuskraa et al. 2011).

Mineralogy and lithology are important for:

1. Quantifying TOC.

2. Reducing porosity uncertainty.

3. Identifying shale lithofacies.

4. Indicating variations in mechanical rock properties including brittleness.

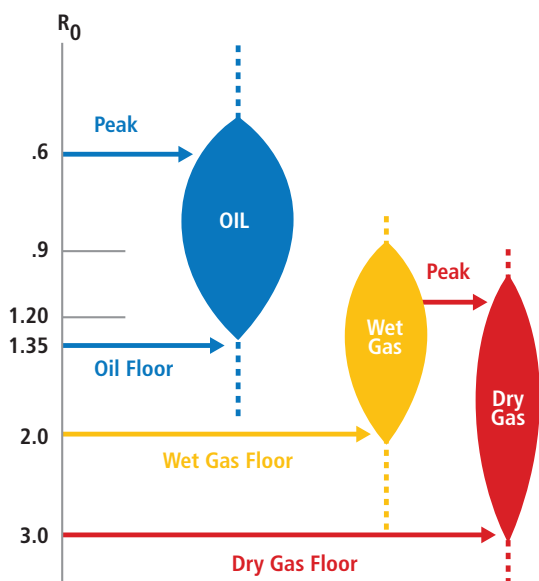5. Assisting in planning well hydraulic fracturing and completion designs.

Fig. 3.4—Thermal maturation scale. (From Kuuskra et al. 2011.)

Most shale reservoirs can be chemostratigraphically classified into three primary lithofacies—siliceous mudstone (such as the Barnett), calcareous mudstone lithofacies, and organic mudstone lithofacies. Additional lithofacies have been identified in some reservoirs based on their unique characteristics. Lithology and mineralogy information is obtained from conventional and pulsed neuron log responses, laboratory analysis of cores and cuttings, and mineral spectroscopy analyses. TOC is quantified by the amount and vertical distribution of kerogen, kerogen type, level of maturity, and mineral spectroscopy plus core analysis. Log-derived and computed geomechanical properties include minimum horizontal stress (SH_{Min}), Poisson's ratio, Young's modulus, fracture migration, and static mechanical properties. Brittleness indicators that are used for identifying best interval to initiate a fracture and location at the vertical from which to drill horizontal laterals are computed from mineralogy and geomechanical brittleness and hardness (Jacobi et al. 2009; LeCompte et al. 2009; Pemper et al. 2009; Mitra et al. 2010).

Geomechanics considerations are significant in the development of unconventional resources in general, not just shale resources. Comments here are also applicable to coalbed methane and tight gas and oil formations. The stress regime in a basin must be considered during well drilling, fracturing, and production. Well orientation is dictated by in-situ stress systems and wellbore stability during drilling. In general, initiating a fracture depends on the stresses around the wellbore—both from the geologically produced tectonic effects and from changes in stresses produced by the fracture growth. Fractures are difficult to initiate where total rock stresses are very high. A major consideration during shale production is the stress evolution accompanying drawdown and depletion activity. It is now well established that reservoir pressure changes have an effect on both the stress magnitudes and direction in the sub-surface (Addis and Yassir 2010; King 2010).

Presence, location, and orientation of natural fractures in shale are significant with respect to the hydraulic fracturing process. In these naturally fractured reservoirs, well placement for initial development is dictated by two sub-surface factors:

1. Location and orientation of natural fracture sets, orientation of the most conductive natural fracture set, and in-situ stress magnitudes and directions

2. Propagation direction of hydraulic fractures from the wellbore and the intersection of natural fracture system (Addis and Yassir 2010)

Table 3.2—Free gas, sorbed gas, and dissolved gas storage methods.

Shale Gas Type →	Free Gas	Sorbed Gas	Dissolved Gas
Storage Method	In the rock matrix porosity	Adsorbed (chemically bound) to the organic matter (kerogen) and mineral surfaces within the natural fractures	In the hydrocarbon liquids present in the bitumen
	In the natural fractures	Absorbed (physically bound) to the organic matter (kerogen) and mineral surfaces within the matrix rock	

One purpose of hydraulic fracturing is to connect the existing natural fractures to create a complex network of pathways that enable hydrocarbons to enter the wellbore (King 2010; Jenkins and Boyer 2008). For shale gas, the gas (free and sorbed) is stored in three ways in a shale reservoir, as described in **Table 3.2**.

To obtain the total amount of gas in place (GIP), free gas, sorbed gas, and dissolved gas must be added together. Free gas is the *initial flush* production that occurs early, during the first few years of the life of a well. The absorbed gas volume is often significantly more than the free gas stored in the matrix porosity. Gas contents can exceed apparent free gas-filled porosity by 6 to 8 times where organic content is high (Warlick 2010). However, sorbed gas is produced by diffusion or desorption and does not occur until later in the field life after the reservoir pressure has declined. It is generally accepted that sorbed gas does not have an appreciable effect on shale field economics (because it is not produced early in well life), but sorbed gas can constitute a significant part of GIP in some shale reservoirs. Dissolved gas is only a small part of GIP in most shale reservoirs.

Most shale gas wells produce only dry gas (90% methane) and essentially little water. A notable exception to this is the Eagle Ford where part of the play produces dry gas, part wet gas, and another part produces shale oil. It is understood, based on operator experience, that the emerging Utica shale basin is similar to the Eagle Ford with dry gas, wet gas, and oil areas. The Antrim and New Albany shale do produce formation water. Concerns about water production handling, treating, re-use, or disposal due to flowback water from fracturing is discussed in Chapter 17.

Shale gas and oil wells display a rather unique decline profile character. Shale gas wells typically exhibit gas storage and flow characteristics uniquely tied to geology and physics (Rushing et al. 2008). Initial production rates are relatively low, in the 2-10+ MMcfd range (horizontal wells), and these rates decline rather rapidly.

However, it seems that a well producing around less than 100 Mcfd would be approaching the economic limit. Shale oil wells have exhibited initial productivity rates in the range of 250 to 2,000 BOPD. Some examples of typical decline type curves are shown as **Fig. 3.5** for Barnett shale gas, in **Fig. 3.6** for Eagle Ford shale gas, in **Fig. 3.7** for Bakken shale oil, and in **Fig. 3.8** for Eagle Ford shale oil.

Shale natural gas is either *biogenic* in origin, formed by the action of biologic organisms breaking down organic material within the shale, or of *thermogenic* origin formed at depth and high temperatures. Relatively few biogenic gas systems are producing economic gas within the United States. The Antrim shale in Michigan is one of those systems. Another is the New Albany shale of Illinois and Indiana. Wells producing from the biogenic Antrim and New Albany shales have relatively low production rates, e.g., 135 Mcfd; however, they will produce for a long time: 20+ years. In many cases large quantities of water are produced before, or as, any gas is produced. Gas production is closely tied to dewatering the system (like coalbed methane) to gain economic production. Geochemistrical analysis indicates that the water is usually fairly fresh.

The majority of producing shale gas reservoirs in the US are thermogenic systems. Thermogenic gas occurs as a result of primary thermal cracking of the organic matter into a gaseous phase. Secondary thermal cracking of remaining liquids also occurs. Thermal maturity in these reservoirs determines the type of hydrocarbon that will be generated. Gas produced in a thermogenic environment will be relatively dry (Economides and Martin 2007). Reservoir pressure is one of the key parameters to how well conventional gas (and oil) reservoirs perform. Pressure controls production rates and is used along with boundary conditions to predict recovery. Shale reservoirs range from normally pressured to highly overpressured. The higher pressured shale reservoirs, like the Haynesville, have higher initial production (IP) and higher recovery than others. Higher reservoir pressures do have an effect on the hydraulic fracturing designs; especially selection of appropriate proppants, as higher reservoir pressure can crush some types of proppants.

Depositional environment of shale is important, particularly whether it is marine or non-marine. Marine-deposited shale tends to have lower clay content and be high in brittle materials, such as quartz, feldspar, and carbonates. Because of
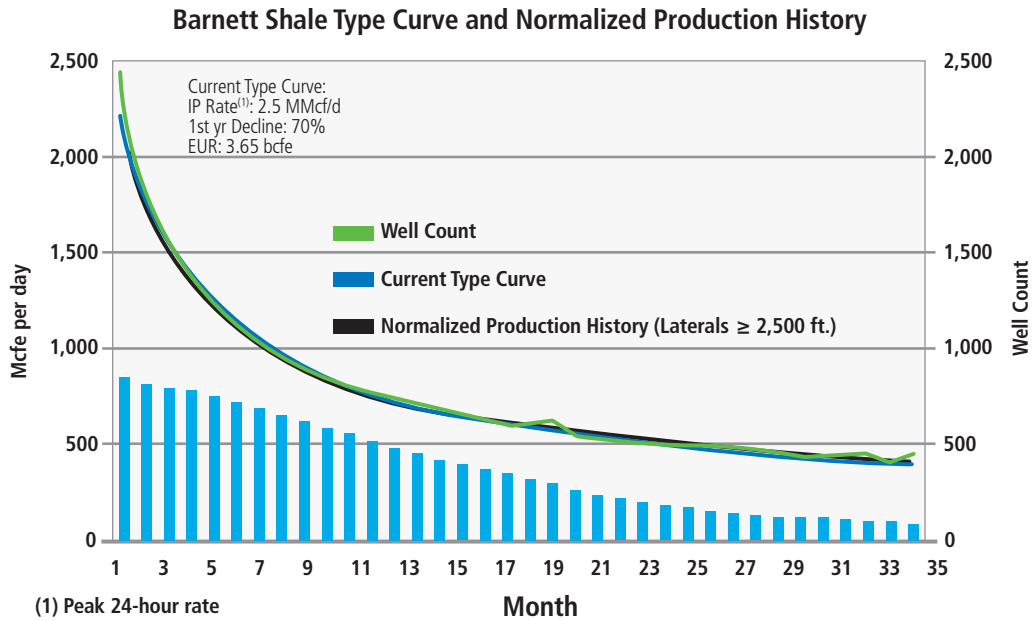
Barnett Shale Type Curve and Normalized Production History

Current Type Curve:
IP Rate[(1)]: 2.5 MMcf/d
1st yr Decline: 70%
EUR: 3.65 bcfe

Legend:
- **Well Count**
- **Current Type Curve**
- **Normalized Production History (Laterals ≥ 2,500 ft.)**

(1) Peak 24-hour rate

Month

Fig. 3.5—Barnett shale gas. (From EIA 2011.)

EUR: 5.5 BCFE
Drill & Complete: $6.0MM
Initial Rate: 9.5 MM/d
1st year Decline: 75%
Terminal Decline: 6%
b factor: 1.1

75% of EUR produced in 10 Years

30% of EUR produced in 1st Year

Legend:
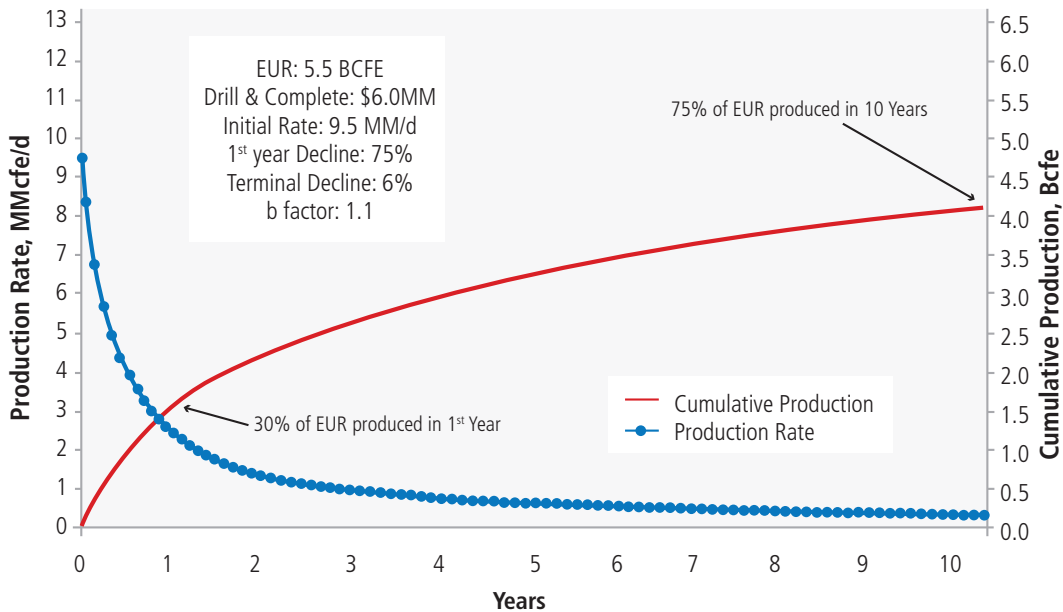- Cumulative Production
- Production Rate

Years

Fig. 3.6—Eagle Ford shale gas. (From EIA 2011.)

this mineralogy, marine-deposited shales respond favorably to hydraulic fracturing. Non-marine deposited shale, i.e., lacustrine and fluvial, tend to be higher in clay, more ductile, and less responsive to hydraulic fracturing. Transgressive systems (also called onlap systems, due to a transgression) are characterized by higher TOC and quartz and less clay. Shale deposited during transgressive systems not only responds favorably to hydraulic fracturing, but also can have higher hydrocarbon recoveries. Alternatively, regressive systems are characterized by lower TOC and quartz and higher clay content. Shales deposited during regression are less responsive to hydraulic fracturing and have lower hydrocarbon recoveries. Thus, depositional environment for shale can be important along with thickness and reservoir pressure.
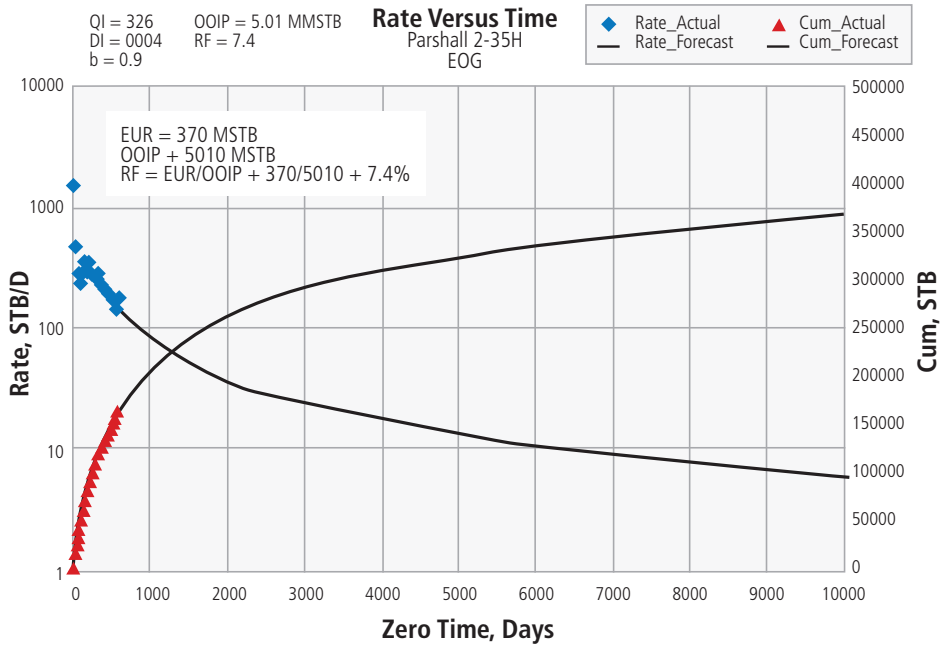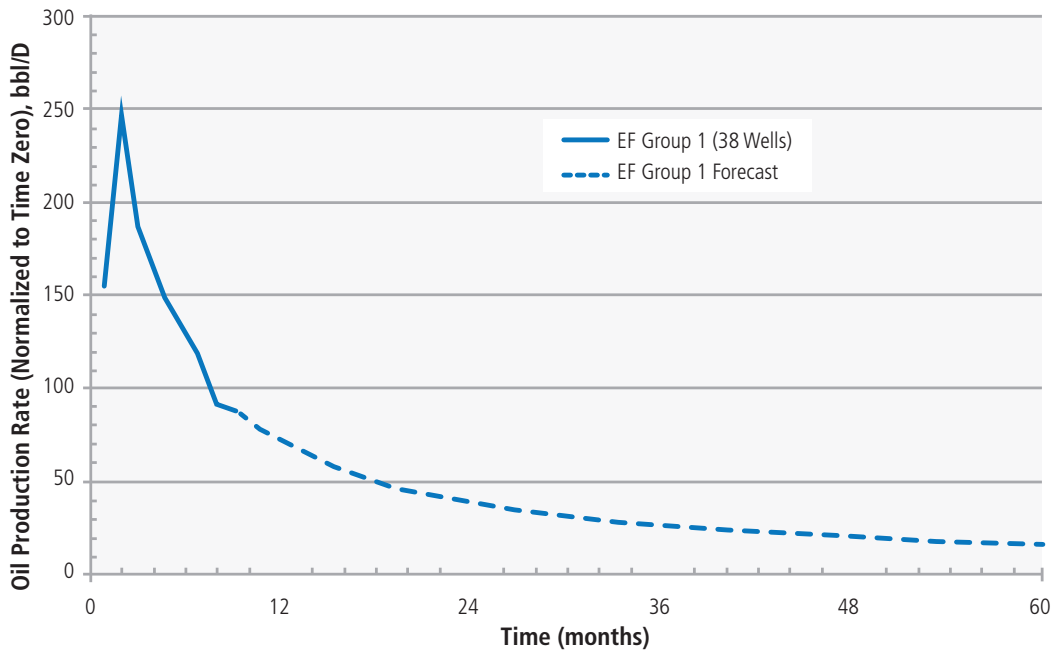
Fig. 3.7—Bakken shale oil. (From Aaron 2009.)

Fig. 3.8—Eagle Ford shale oil. (From Martin et al. 2011.)

3.5 Specific Considerations for Tight Oil and Gas

"In the 1970s the US government decided that the definition of a tight gas reservoir is one in which the expected value of permeability to gas flow would be less than 0.1 md. This definition was a political definition that has been used to determine which wells would receive federal and/or state tax credits for producing gas from tight reservoirs," (Holditch 2006). Holditch wrote that the tight gas definition is a function of a number of physical and economic factors.

Another definition of a tight gas reservoir is "a reservoir that cannot be produced at economic flow rates nor

recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by the use of a horizontal wellbore or multilateral wellbores," (Holditch 2006; Shrivastava and Lusatia 2011). Other authors say that flow rate—rather than permeability—should be the measure of what is termed a tight gas reservoir. Certainly that approach has merit, since some reservoirs with 10+md permeability are being fractured and the flow rate is being increased.

There are no "typical" tight oil and gas reservoirs. They can be:

- Deep or shallow
- High-pressure or low-pressure
- High-temperature or low-temperature
- Blanket or lenticular
- Stratigraphic, structural, and channel-influenced
- Homogeneous or naturally fractured
- Single layer or multiple layers
- Sandstone or carbonate
- Shale oil and gas—at times defined as tight oil and gas

Additionally, coal seam gas (CSG)—also referred to as coalbed methane—can be included in this category.

Unlike shale gas and coalbed methane, the hydrocarbons found in tight reservoirs are sourced in another formation, migrate, and then are trapped (like conventional gas) in the formation where they are found. Discrete gas and water contacts are usually absent, but wells may produce water. Microscopic study of pore and permeability relationships indicates the existence of two varieties of tight oil and gas reservoirs. One variety is *tight* because of the fine grain size of the rock. The second variety is *tight* because the rock is relatively tightly cemented, diagnetically altered, and has pores that are poorly connected by small pore throats and capillaries. What have we learned about the tight oil and

gas development in the US? Based on our observations and available statistics from a number of sources, the following conclusions can be drawn and information gathered:

- Tight gas wells must be fracture-stimulated to produce commercially.
- Average well spacing is now (following several field development iterations) 5 to 10 acres in the lenticular formations (Pinedale Anticline, and Piceance).
- Formation thickness ranges from 600 to 6,000 ft.
- Formation depth ranges from 4,700 to 20,000 ft.
- Multiwells pads contain wells that are S-shaped, directional, or vertical (Pinedale Anticline and Piceance).
- Some wells are horizontal and multilateral (Texas Panhandle, Anadarko basin).
- Well IPs range from < 3 to 20 MMcfd.
- Production is dry gas, wet gas, and water.
- Tight gas formations producing water require deliquification (also called dewatering), in particular for coalbed methane.
- Wells exhibit high decline rates in the first few years of production.
- A high number of wells are required to develop shale (low per well EUR).

The four tight gas basins that produce most of the US tight gas are the Pinedale Anticline, Anadarko, Piceance, and Deep Bossier. Step-by-step procedures to effectively develop these tight oil and gas fields have been documented by Ahmed and Jones (1981); Abou-Sayed and Ahmed (1984); Ahmed and Cannon (1985). **Table 3.3** is a comparison of these US tight gas basins.

All tight wells, gas in particular, display the unique decline curve profile similar to shale but not as drastic. **Fig. 3.9** shows several modeled production profiles of various tight gas well scenarios compared to the profile for a conventional gas well plotted from actual measurements obtained from a productive field. Plots show that the initial rates and EUR per well are significantly less than those for conventional gas wells.

Table 3.3—Comparison of the four significant US tight basins. (Source from Warlick 2010.)

| BASIN	Depth, ft.	Thickness, ft.	IP, MMcfd	EUR/Well, Bcf	Production	Well Spacing, ac	Formation	Well Cost, $MM	TRR, Tcf
Pinedale Anticline	7,000–14,000	5,000–6,000	9	6.5	Gas + Water	5	Lenticular, Stacked	3	73
Piceance	6,500–9,000	1,500–4,500	3	3–8	Dry Gas + Water	10 (fr 160)	Lenticular, Stacked	1.5–4.0	7
Anadarko	4,700–13,000	3,500–3,600	10–15	7.0	Wet Gas	80	Granite Washes	7.0–8.5	6
Deep Bossier	16,300	600	15–20	1.5–2.0	Dry Gas, No Water	20	Lenticular	7.6–11.0	6
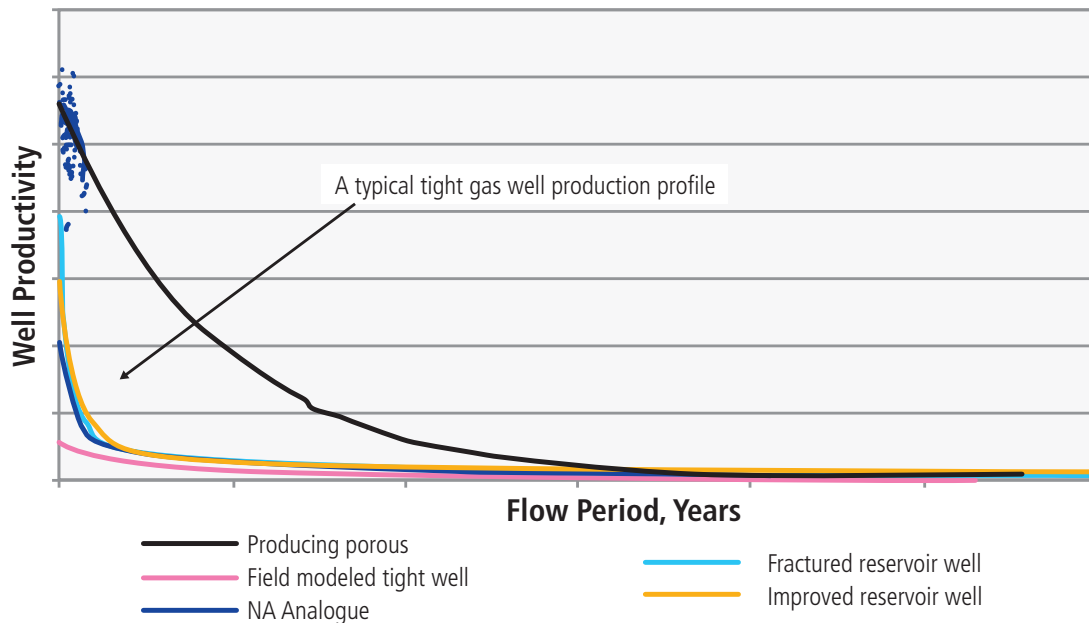
Fig. 3.9—Modeled typical tight gas production profiles compare to a conventional gas well. (Al Kindi et al. 2011.)

3.6 Specific Considerations for Coalbed Methane

The flow and production mechanism within coalbed methane has more similarity to shale oil and gas than to the production of oil or gas associated with tight sedimentary rocks. The initial flow is dictated by the stored gas and water in the fracture network (both the orthogonal butt and face cleats as illustrated in **Fig. 3.10**). Subsequent long-term
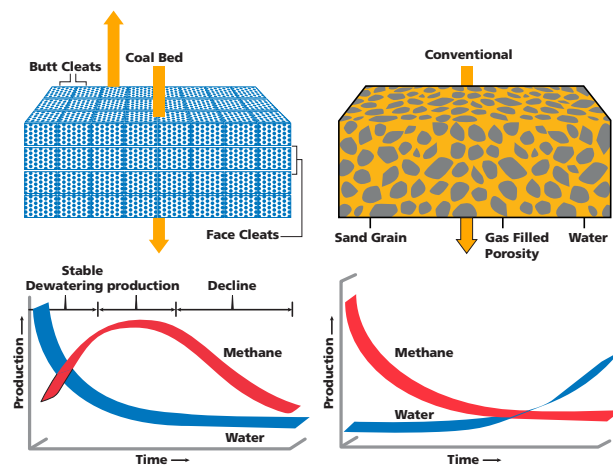

Fig. 3.10 —The flow channels (cleat system) and the production mechanism via dewatering. (From Brown 2002.)

production is controlled by desorption of the gas from the coal matrix as reservoir pressure drops due to long-term water production.

The rate of desorption on the other hand is controlled by macerals (the microscopically recognizable components of coal, analogous to minerals in inorganic rocks), which, in turn, can define the percentage of vitrinite. Vitrinite reflectance values indicate when the coal has reached the gas-generating phase (**Fig. 3.11**), and a rank of class A, a high-volatile bituminous coal (**Table 3.4** for coal rank classes).

Other relevant parameters for further detailed understanding include *cation exchange capacity* (to detect and quantify hydratable clay fractions), *petrographic analysis* (to define pore or flow that channels like the butt and face cleats) and *geophysical logging* (to measure in-situ inferences) allow the estimation of almost all the above parameters in italics as discussed in detail by Ahmed and Newberry (1988). **Fig. 3.12** illustrates a desorption isotherm suggesting the potential production rate and ultimate recovery over a certain pressure and temperature regime while **Fig. 3.13** illustrates the various items that define the adsorption Isotherm (the amount of gas that the coal in question can adsorb as stored methane gas.
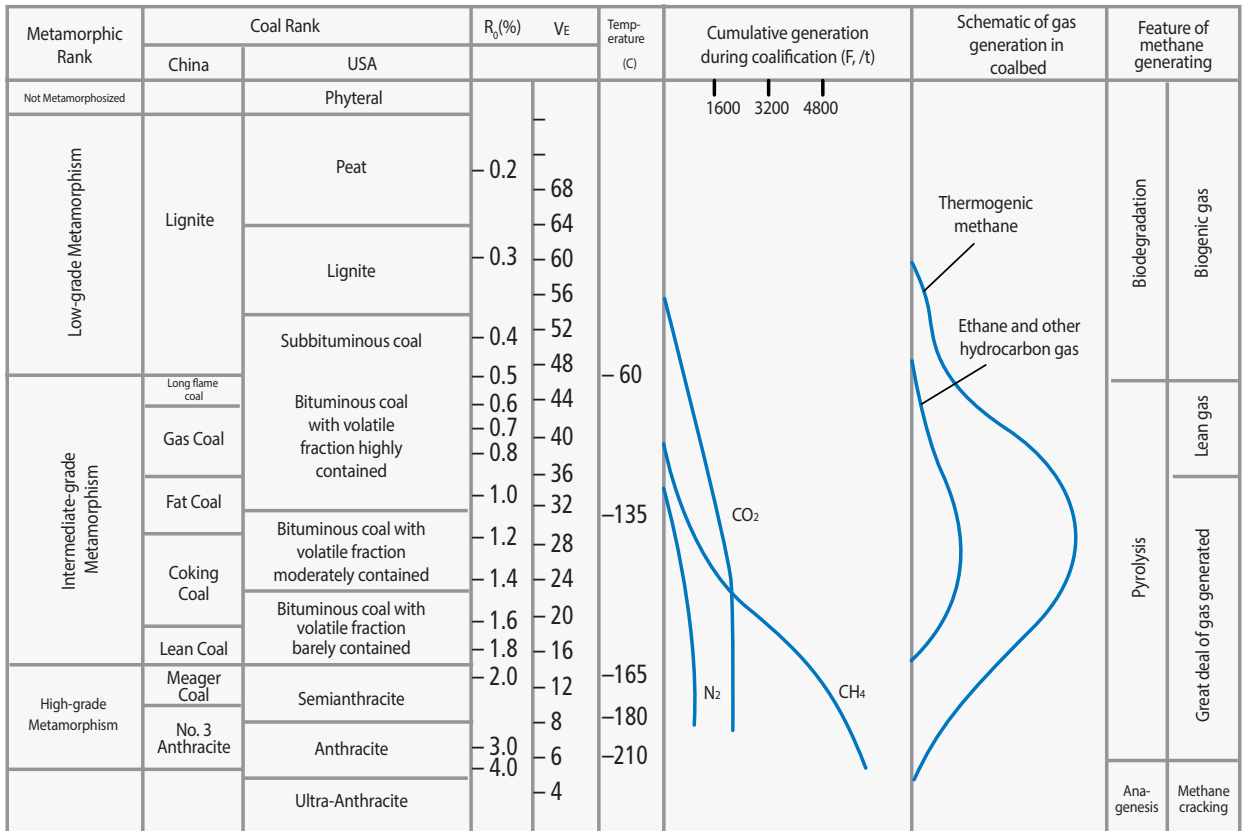
Metamorphic Rank	Coal Rank		R₀(%)	Vₑ	Temperature (C)	Cumulative generation during coalification (F, /t)	Schematic of gas generation in coalbed	Feature of methane generating	
	China	USA	R_o(%)	V_E	(C)	1600 3200 4800			
Not Metamorphosized		Phyteral						Biodegradation	Biogenic gas
Low-grade Metamorphism	Lignite	Peat	0.2	68			Thermogenic methane		
				64					
		Lignite	0.3	60					
				56					
		Subbituminous coal	0.4	52					
Intermediate-grade Metamorphism	Long flame coal		0.5	48	60		Ethane and other hydrocarbon gas	Pyrolysis	Lean gas
	Gas Coal	Bituminous coal with volatile fraction highly contained	0.6 0.7 0.8	44 40 36					
	Fat Coal		1.0	32	135	CO₂			Great deal of gas generated
	Coking Coal	Bituminous coal with volatile fraction moderately contained	1.2 1.4	28 24					
	Lean Coal	Bituminous coal with volatile fraction barely contained	1.6 1.8	20 16					
High-grade Metamorphism	Meager Coal	Semianthracite	2.0	12	165	N₂ CH₄			
	No. 3 Anthracite	Anthracite	3.0 4.0	8 6	180 210				
		Ultra-Anthracite		4				Anagenesis	Methane cracking

Fig. 3.11—Coal rank and hydrocarbon generation potential (after Qin and Zeng 1995 in Unconventional Petroleum Geology).

Table 3.4—Vitrinite reflectance limits (in oil) and A, S, T, and M coal rank classes.

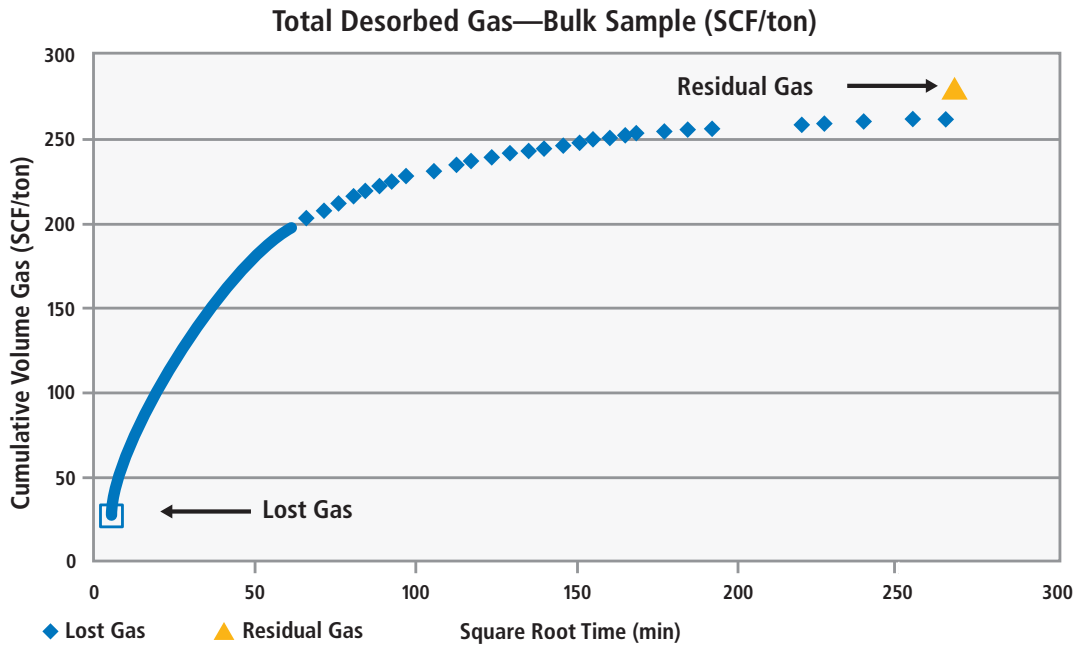| Rank	Maximum Reflectance %
Sub-Bituminous	Less than 0.47
High Volatile Bituminous C	0.47-0.57
High Volatile Bituminous B	.057-0.71
High Volatile Bituminous A	0.71-1.10
Medium Volatile Bituminous	1.10-1.50
Low Volatile Bituminous	1.50-2.05
Semi-Anthracite	2.05-3.00 (approx.)
Anthracite	Greater than 3.00

Fig. 3.12—Example of a desorption isotherm as measured in the laboratory environment. (From Waechter et al. 2004.)
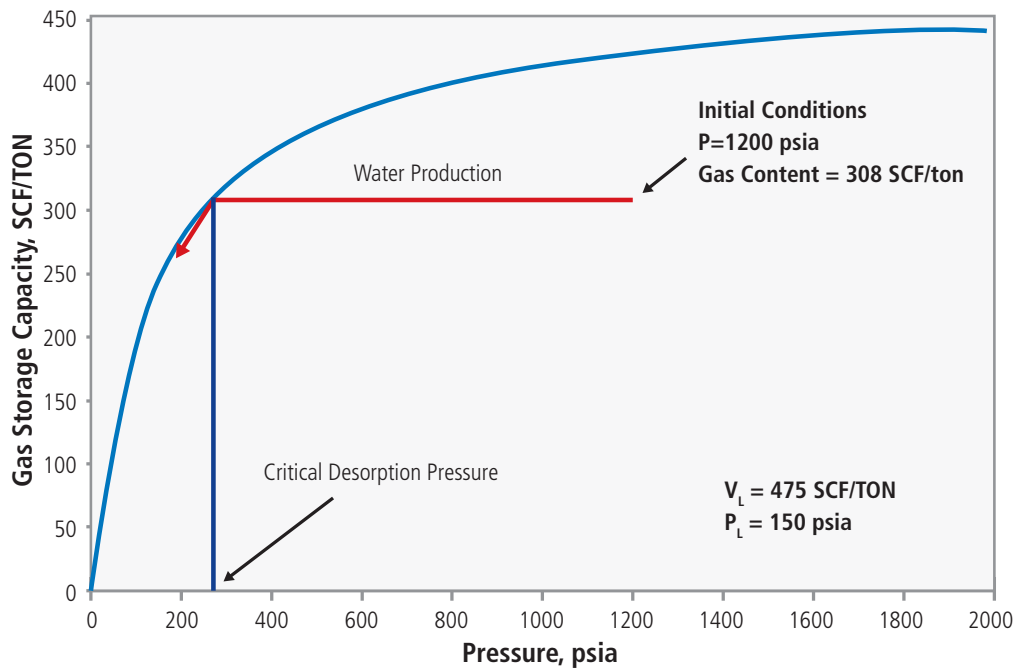

Fig 3.13—A typical adsorbtion isotherm. (From Aminian, West Virginia University.)

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