Link between Endowments, Economics and Environment in Conventional and Unconventional Gas Reservoirs

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Abstract

This paper presents a methodology for connecting endowments, economics and the environment in conventional, tight, shale and coalbed methane (CBM) reservoirs. The volumetric estimates are generated by a variable shape distribution model (VSD). The VSD has been shown in the past to be useful for the evaluation of conventional and tight gas reservoirs. However, this is the first paper in which the method is used to also include shale gas and CBM formations. Results indicate a total gas endowment of 70000 tcf, split between 15000 tcf in conventional reservoirs, 15000 tcf in tight gas, 30000 tcf in shale gas and 10000 tcf in CBM reservoirs. Thus, natural gas formations have potential to provide a significant contribution to global energy demand estimated at approximately 790 quads by 2035.

A common thread between unconventional formations is that nearly all of them must be hydraulically fractured to attain commercial production. A significant volume of data indicates that the probabilities of hydraulic fracturing (fracking) fluids and/or methane contaminating ground water through the hydraulically-created fractures are very low. Since fracking has also raised questions about the economic viability of producing unconventional gas in some parts of the world, supply curves are estimated in this paper for the global gas portfolio. The curves show that, in some cases, the costs of producing gas from unconventional reservoirs are comparable to those of conventional gas.

The conclusion is that there is enough natural gas to supply the energy market for nearly 400 years at current rates of consumption and 110 years with a growth rate in production of 2% per year. With appropriate regulation, this may be done safely, commercially, and in a manner that is more benign to the environment as compared with other fossil fuels.

Introduction

This study aims to present an overview of various aspects associated with unconventional natural gas. Apart from serving as an extensive literature review, the paper also presents original estimates of unconventional gas quantities and production costs. We argue that the topics of focus are highly interconnected. For instance, **Figure 1** is a pentagon showing the link between rocks (geology), hydraulic fracturing, economics, environment, and the global gas portfolio. Our view is that there must be equilibrium in the pentagon to provide a win-win situation for society at large. All corners in the pentagon are interrelated and there is no need to sacrifice one for benefit another. It has been shown that there is a significant gas endowment in conventional reservoirs. However, we have to also unlock natural gas stored in unconventional formations to ensure that gas plays an important role in satisfying future energy consumption. We cannot produce it economically without hydraulically fracturing the unconventional formations. At the same time, we cannot sacrifice the environment solely for economic gain and nothing but the highest environmental standards are acceptable. All stakeholders must act responsibly to generate the win-win scenarios.

The natural gas industry is at present a victim of its own success. A gas bubble has resulted in a drop in prices during the last few years in North America, which has made the economics unattractive for oil and gas companies. The gas bubble is the result of innovation brought about by the oil and gas industry. But innovation is nothing new in the oil and gas industry. For example, the Bureau of Economic Geology at the University of Texas (Austin) presented an evaluation of Federal, State and private investment in unconventional natural gas research in the US [1]. The study indicated that “the supply curves benefited greatly from natural gas research and the successful application of technology.” Although the R&D investment was relatively modest, the tight gas production curve did show a large positive increase in slope in 1985 following $165 million of combined investment in research by the Department of Energy (DOE) and the Gas Research Institute (GRI). “Studies were focused on advanced stimulation technology, the greater Green River Basin, and the Piceance Basin.” Subsequently, shale gas came of age in the United States with innovation in the drilling of horizontal wells and development of technology for multi-stage hydraulic fracturing; while hydraulic fracturing has been in practice commercially since 1949, the multi-stage advances have been critical in lowering costs. Although the results have been outstanding, the forecasts by 2003 were dire as some experts indicated there was going to be “irreversible decline” in natural gas production in North America and that gas production rates would “fall off a cliff.” For example, the following statement by Mathew Simmons (2003) created some concern: “people need to understand the concept of peaking and irreversible decline. It's a sharper issue with gas, which doesn't follow a bell curve but tends to fall off a cliff. Pray for no hurricanes and to stop the erosion of natural gas supplies. Under the best of circumstances, if all prayers are answered there will be no crisis for maybe two years. After that it's a certainty.” [2] These forecasts got some attention when production fell dramatically in the US as a result of hurricanes Katrina and Rita (**Figure 2A**). However, actual gas production became a mirror image of the “fall off a cliff” prediction (**Figure 2B**). The success, highly dependent on multi-stage hydraulic fracturing, has resulted in accusations that this type of stimulation leads to environmental problems - particularly related to contamination of ground water by methane and chemicals used in the fracturing jobs. However, the possibilities of this happening through hydraulic fractures created during stimulation jobs are very slim. To reduce the probabilities of environmental problems, special care has to be taken during the wellbore construction and casing cementation. As society will require increasing energy in the future, the use of natural gas should be encouraged as this is the cleanest fossil fuel available (as summarized in the environmental segment of **Table 1)**.

The development of effective technology for tight and shale gas formations can be explained using Foster's S-shape curve (1986) adapted to the case of unconventional gas in the United States, Canada and the world [3]. **Figure 3(A)** shows our interpretation of innovation associated with unconventional natural gas in the United States. The very small amount of research funding indicated above provided a seed for initially slow but encouraging advancement. This corresponds to the end of the S curve at the bottom lefthand corner. This led to many additional investments by the oil industry in the United States on tight gas sandstones and subsequently shale gas (and liquids), thus moving through the steep part of the S curve. Foster has indicated that "youthful attackers" have generally provided the possibility of new technological development and innovation. The same holds true in the oil and gas industry where smaller companies took the lead on development of unconventional resources. The steep part of the S-curve is where, to paraphrase Foster, all hell broke loose as "the key knowledge necessary to make advances" was put in place. The flat part at the top of the curve has not yet been reached. Canada did successfully follow the United States, making the necessary improvements along the way to fix technical discontinuities, and the world is following suit. This is highlighted by three successive S-shaped curves in **Figure 3(B)**. However, since the top of the S-curve has not been reached in the United States and Canada, the steep part of the S-curve could be represented by a single segment. The flattening at the top of **Figure 3(B)** for the world represents the maturation of the global natural gas industry when "it becomes more and more difficult and expensive to make technical progress". Presumably, this will happen in the coming decades. Natural gas is abundant and will provide a bridge and the necessary time to develop non-fossil, renewable sources that eventually will result in lower and zero carbon emissions [4]. However, the technical and commercial viability of these sources will require large amounts of investment in global research and development.

Table 1 provides a synopsis of some advantages of using natural gas over oil - with the general exception of transportation where oil is clearly dominant - as well as a high level view on differences in geological, economic, technological, physical, chemical and environmental issues. Comprehensive descriptions of these topics have been presented in [5, 6]. The objective of **Table 1** is to highlight and summarize issues that are discussed in more detail throughout this paper.

Geology

All hydrocarbons and types of reservoirs can be integrated under the umbrella of a Total Petroleum System. An excellent explanation of the Petroleum System has been presented by [7]: "The Petroleum System is a unifying concept that encompasses all of the disparate elements and processes of petroleum geology including a pod of active source rock and all genetically related oil and gas accumulations."

The essential elements of a Petroleum System include the following: (1) Source rock. (2) Reservoir rock. (3) Seal rock. (4) Overburden rock. The Petroleum System includes two processes: (1) Trap formation. (2) Generation–migration–accumulation of hydrocarbons. These essential elements and processes must be correctly placed in time and space so that organic matter included in a source rock can be converted into a petroleum accumulation. A Petroleum System exists wherever all these essential elements and processes are known to occur or are thought to have a reasonable chance or probability to occur [7].

The segments of the Total Petroleum System described above, dealing with conventional and unconventional gas reservoirs, are considered in this paper. Conventional gas reservoirs include primarily sandstone and carbonate reservoirs. Unconventional gas reservoirs include tight formations (sandstones and carbonates), shale gas and coalbed methane (CBM). Natural gas hydrates are also part of the unconventional gas group but they are not considered in this paper given the wide range of available quantitative estimates. It should be noted, however, that global research on hydrate development is ongoing. Japan in particular views hydrate development as an important long-term strategy considering the nation's high energy import-dependency [8].

As highlighted in **Table 1,** there are significant geologic differences between oil and gas. As the gas window generally occurs at deeper depths because of larger pressure and temperatures, the volumes of gas-in-place in deep basins are much larger than the volumes of oil. Porosities, permeabilities and pore throat apertures required for fluid flow can be significantly smaller in the case of natural gas as compared to oil. Although exploration for oil has been much larger than that of gas, the geographic presence of gas is greater and more ubiquitous compared to oil.

Conventional Reservoirs.- In general, a petroleum reservoir consists of source rock, reservoir rock, seal rock, trap, and fluid content [9]. Source rock, or source environment, is believed to be responsible for the origin of petroleum. Most geologists believe that the origin of petroleum is organic, related mainly to plants which were altered by pressure, temperature, and bacteria.

It is difficult to prove that oil actually came from a definite source. However, it is believed that the source rock is usually near the hydrocarbon reservoir, i.e., that petroleum was formed within that particular area. Source rock is difficult to identify because it usually contains no visible hydrocarbons. According to [10], the main source rock is shale, followed by limestone.

Reservoir rock is provided by porous and permeable beds. Precise determination of porosity is important for accurate calculations of hydrocarbon-in-place. Permeabilities are important parameters in calculating flow capacities. The same holds true for naturally fractured reservoirs. Igneous, sedimentary, or metamorphic rocks can make an acceptable fracture reservoir. However, most of the world's known hydrocarbon accumulations occur in carbonate and sandstone rocks [11].

Seal rock confines hydrocarbons in the reservoir rock because of its extremely low level of permeability. The most important seal is shale, followed by carbonate rocks and evaporites. A trap is formed by impervious material which surrounds the reservoir rock above a certain level. The trap holds the hydrocarbons in the reservoir.

Tight Gas Reservoirs.- The most common pore structure in tight formation consists of very small pores which are connected to each other via very narrow tortuous slots (**Figure 4**). Slots are the result of cooling and basin uplifting that creates grain bound microfractures [12]. Even though these slots do not necessarily contribute significantly to porosity, they have a significant effect on permeability and consequently on the flow of gas through the tight porous media [13]. The precipitation of silica and/or carbonate cements is among the most significant factors in the transformation of the original rock fabric [14-18].

Tight gas reservoirs in the Western Canada Sedimentary Basin (WCSB) are found in basin-centered continuous gas accumulations characterized by [19, 20]:

- Abnormally low or high pressures
- Low permeability (generally $\leq$ 0.1 md)
- Continuous gas saturation
- No down-dip water leg

If any one of the above elements is missing the reservoir cannot be treated as a continuous gas accumulation. In the case of the Western Canada Sedimentary Basin, there is water blockage up-structure from tight gas reservoirs. The physical impossibility of this kind of trap holding for millions of years has been questioned sometimes in the past. However, it does occur as shown conclusively by [21] with the use of reservoir simulation.

However, it is possible to have conventional structural or stratigraphic traps within a continuous gas accumulation. In other words, within the gas saturated basin-centered accumulations there could be water bearing zones as well as inter-bedded conventional reservoirs [22]. The concept of continuous gas accumulations has been challenged by [23] who indicated that most tight gas fields occur in low-permeability reservoirs in conventional structural, stratigraphic or combination traps that are usually referred to as “sweet spots.” In practice, tight gas reservoirs can be found in both continuous and conventional accumulations in different places around the world.

Note that lithology is not part of the four requirements listed above. As a result, the name “tight gas sands,” although deeply rooted in the gas industry, is somewhat misleading. Probably it would be more accurate to call them simply “tight gas reservoirs” as the same four elements have been reported, for example, in carbonate reservoirs.

The geological evaluation of tight gas resources represents particular challenges, and an integrated, multi-scale approach should be considered to account for the complexities associated with these types of reservoirs [13]. The definition of depositional, petrographic, and hydraulic rock types, proposed by [24], is a good approach to capture characteristics rock properties of tight gas sandstones.

Shale Gas Reservoirs.- There have been significant advances in the study of shale gas reservoirs that have been reported in the literature [25-30]. A common misconception is that production of natural gas from shales started only a few years ago. This is not the case. Actually, contrary to popular belief, natural gas from shales was developed in the past. We have known about shale gas for decades, and by 1980 hydraulic fracturing had been used in North America for several years to maximize recovery from gas wells. Some of the techniques used up to that time included water fracturing, gas fracturing, methanol fracturing, foam fracturing, acid-methanol fracturing and even shooting with nitroglycerin. By 1980 there were thousands of shale vertical wells producing natural gas commercially from the Appalachian basin in eastern United States [31, 32]. And the original documented production of natural gas from shales goes back to the year 1821. What is new and outstanding, particularly during the last 15 years, is the innovation associated with the development of technologies to drill horizontal wells that can be hydraulically fractured in multiple stages going from 200 m apart to 100 m and more recently to less than 50 m and moving into more than 60 stages per well. This combined with the capability of drilling multi-laterals has led to the increases in gas production attained in the United States during the last few years. Another common misconception is that linear flow in hydraulically fractured shale gas wells without observing boundary dominated flow is a new phenomena. This was actually observed using data of Devonian shale gas wells drilled in the early 1950's and analyzed in the late 1970's as shown on **Figure 5** [33]. In these cases linear flow went for over 25 years.

In shale gas formations, natural gas is generated in the shale and remains within the shale, although parts of the gas can migrate and be trapped in other formations (for example in tight gas reservoirs). Consequently the shale is both source rock and reservoir rock. This is opposed to 'tight gas' where the rocks constitute the reservoir storing gas that has migrates from a source rock. Grains and pores are smaller in shales as compared with tight and conventional gas formations. Gas is trapped and stored in shale in different ways (1) as adsorbed gas into the kerogen material, (2) free gas trapped in nonorganic inter-particle (matrix) porosity, (3) free gas trapped in microfracture porosity, (4) free gas stored in hydraulic fractures created during the stimulation of the shale reservoir, and (5) free gas trapped in a pore network developed within the organic matter or kerogen. The latter is a rather recent and extraordinary advancement [28, 29] with significant practical implications that can help explain the larger than anticipated recovery of natural gas from some of these formations. Viscous flow generally dominates in tight gas formations. However, flow in shale reservoirs might deviate from Darcy's law mainly due to two specific phenomena: Gas slippage and inertial flow. Not taking into account the relevant modifications can lead to significant errors in flow calculations [13].

Coalbed Methane (CBM).- The coalbed methane industry follows the tradition of British mining engineers and calls the microfractures in coal seams cleats. The larger dominant micro fractures are called face cleats. The smaller micro fractures that go perpendicular to face cleats are called butt cleats. They are very short and usually are interrupted at the face cleats. Coal bed seams can be represented by dual-porosity models composed of matrix and fractures, which allow the determination of cleat (fracture) porosity from well logs [34]. **Figure 6** shows magnetic resonance image (MRI) scans of core samples in thin slices. The 16 images show the cleat system as white lines, allowing an estimate of fracture spacing. The white line signal arises from imbibed water.

The matrix blocks are made up of micropores that are too small to contain water or any other liquids but store methane molecules adsorbed onto the surface of the coal matrix micropores. Compressed gas in micropores makes only a small portion of gas in the matrix of coal [35]. Cleats usually contain 100% water saturation at discovery and require de-watering to allow the commercial production of methane. There are some instances, however, when cleats are 100% saturated with natural gas at discovery. This is the case of the Horseshoe Canyon formation in Alberta, Canada. Since no de-watering is required this type of reservoir is known as "Dry CBM".

Coalbed acts as both source and reservoir for methane. The dominant transport mechanism in the matrix is diffusion. In the cleat system Darcy's transport mechanism dominates. The dual porosity model introduced by [36] and modified later in different manners is widely used in CBM studies. In some cases triple porosity with dual permeability models has been also adopted to decouple desorption and diffusion processes in matrix blocks [37].

The Adsorbed gas in micropores is usually one molecule thick unless the reservoir pressure is very high [38]. As a result the Langmuir model, commonly used to model adsorption on coal [39], assumes monolayer adsorption. Through numerical simulation, [40] have investigated the effect of sorption time on coalbed methane recovery. The study demonstrates that the smaller the sorption time the faster the sorption/diffusion process. Sorption time is a lumped parameter accounting both for diffusion and desorption time [41]. It controls the rate at which gas molecules are released from micropores into the cleats.

Flow Units.- Several researchers [42-47] have discussed the importance of pore and throat structure (for example size, geometry, distribution, connectivity, and composition) on flow units and storage capacity of porous media focusing particularly on conventional reservoirs. Pore throat apertures have been estimated based on knowledge of process speed, i.e., the ratio of permeability and porosity [48, 49]. In turn, these pore throat apertures has been used with reasonable success to anticipate flow rates that can be expected from a given well in oil [50] and gas reservoirs [51].

Real data and simulation at the pore throat level, shows that the same concept can be extended quantitatively from the case of conventional to the case of tight gas and shale gas reservoirs. In order to do that, data from several conventional reservoirs around the world; and tight gas and shale gas reservoirs in North America have been examined. Examples of results are presented in **Figure 7**. The graph is a conventional crossplot of permeability in a logarithmic scale vs. porosity [13, 30, 52].

Corroboration of the practical value of **Figure 7**, developed empirically, has been carried out with the use of pore scale modeling [13]. By applying rules that govern the transport and arrangement of fluids in pores and throats, macroscopic properties (for example, porosity, permeability, capillary pressures and relative permeabilities) can then be estimated across the network, which in practice consists of several thousand pores and throats representing a rock sample of a few millimeters long in each side.

Figure 8 shows summary results of this methodology for conventional, tight and shale reservoirs; and the approximate oil and gas rates that can be anticipated from each flow unit [51]. As indicated in the geological section of **Table 1** the permeability and pore throat apertures required for fluid flow of natural gas are smaller than those required for flow of oil. The graph follows a pore throat aperture format introduced by H. D. Winland [48] who developed the original equation for calculating pore throat aperture at 35% cumulative pore volume. The graph allows an approximation to distinguish between continuous (viscous) flow and diffusion-like flow commonly observed in coalbed and some shale reservoirs. The distinction is made with the use of the Knudsen number. The oil rate estimates in the graph were published by [50]. Stress dependent properties can also be introduced in the flow units evaluation [51].

Hydraulic fracturing

Technological advancements such as horizontal drilling and multistage hydraulic fracturing (see **Table 1**) have made unconventional gas economic in many places around the United States and Canada in spite of low gas prices. Hydraulic fracturing has been nearly always part of the completion program in unconventional gas reservoirs with exceptions in some CBM reservoirs. As indicated previously, innovations leading to the development of technologies to drill horizontal wells that can be hydraulically fractured in multiple stages have been advancing at a rapid pace. The stages have been decreasing continuously from 200 m apart to 100 m and more recently to less than 50 m and moving into more than 60 stages per well. This combined with the capability of drilling multi-laterals and monitoring fracture growth with microseismic data has led to the increases in gas production attained in the United States during the last few years. More recently, the same technologies have been applied to both new and mature oil fields.

Comparisons have been made between open-hole and completed completions but a definitive answer has proved elusive. Brute force under the philosophy of 'the bigger the better' does not work because of economic considerations. This has been illustrated by Taylor et al. [53]. A key question for economic optimization of unconventional gas assets is what fracture spacing to use along a horizontal wellbore. Of equal importance is what spacing to use for multilaterals and the wellbores themselves to affect optimal drainage of the reservoir. In addition, the design of the fracturing treatment itself has to be optimized. To address these questions, Taylor et al. have used a combination of reservoir and fracturing simulation models. The required input data are provided through a combination of advanced well log and core analysis, diagnostic fracture injection testing (DFIT), rate transient analysis (RTA), and characterization of fracture geometry through microseismic monitoring. Fluid rheology is characterized using pressurized rheometers and flow loops.

Figure 9 displays an example of Taylor et al.'s analysis in a cross plot of cumulative gas production vs. fracture spacing over a 10-year time interval. As anticipated the best cumulative gas production is obtained with the smallest fracture spacing (25 m). However, the economic evaluation indicates otherwise; as shown in **Figure 10,** which displays the resulting calculation of profit vs. fracture spacing over ten years. From this graph, it can be concluded that the maximum economic return is obtained with 75 m spacing, though the cumulative gas production is not the largest. What is really surprising (but it should not be) is that the smallest fracture spacing (25 m) never recovers the capital investment. In fact, it provides the worst economic performance. Thus, as indicated above, the use of brute force is not the optimum way of hydraulically fracturing unconventional gas reservoirs.

VSD principles

Petroleum endowment volumes have been estimated previously with a Variable Shape Distribution (VSD) model developed in [54]. According to the United States Geological Survey (USGS) World Petroleum Assessment [55], endowment refers to the sum of known volumes (cumulative production plus remaining reserves) and undiscovered volumes. The VSD, a statistical method known as size distribution analysis, calculates the endowment volumes in petroleum provinces that have not previously been assessed. This type of analysis has historically been successful in complementing geological techniques used to estimate resources in previously unassessed areas [56]. In this study, the VSD model is only briefly described as the focus is on supply curve estimation.

Traditionally, all the methods used to forecast oil and gas volumes have been "based on an assumed form of the size-frequency distribution of the natural population of oil and gas accumulations" [56]. The lognormal and Pareto (fractal) distributions are common size distribution models used to estimate volumes of unassessed areas. These types of statistical distributions are believed to be representative of many natural and social occurrences (e.g. resource distribution in nature; income distribution across population). Some researchers believe that the distribution of nature's resources follow lognormal distributions [57], while others claim the lognormal distribution provides overly pessimistic results [58]. More recently, it has generally been acknowledged that the Pareto distribution tends to overestimate oil and gas resources, while the lognormal distribution tends to underestimate them.

The VSD is unique in that we first observe the curvature (on a log-log plot) given by the size and number of assessed provinces by the USGS [55]. We then develop the VSD model which allows the data to determine the specified relationship between the size and number of provinces. In [54], the model has been used successfully, typically with coefficients of determination (R^2) equal to or greater than 0.98, to match available global data for conventional oil, gas, and natural gas liquids (NGL). The close matches allow us to extend the model out of sample to include previously unassessed provinces in the analysis. As is common in size distribution models, the original sample contains the largest provinces, meaning that most of those previously unassessed will be smaller in terms of volumes [59]. This allows us to estimate key parameters including the slope and intercepts of the theoretical Pareto (fractal) straight line given by the largest provinces. The selection by the USGS of provinces for assessment represents a data generation process and affects the ultimate estimate of the endowment volumes in the unassessed provinces. As stated by [55], "the assessed areas were those judged to be significant on a world scale in terms of known petroleum volumes, geologic potential for new petroleum discoveries, and political or societal importance."

Equation 1 presents the VSD as a nonlinear least squares model. Development of the equation and explanation of its use has been presented elsewhere [54, 60] and need not be repeated here. However, the final equation is presented below for completeness. In particular, the problem is:

$$\min_{\{V_x, a_p, V_s, \psi, S\}} \sum_{i=1}^{n} (V_i - \hat{V}_i)^2 \tag{1}$$

Subject to:

$$\hat{V}_i = \frac{\left\{\left[\left(\dfrac{1}{N_t} - \left(\dfrac{V_m}{V_x}\right)^{\left(\frac{\log N_x - \log N_m}{\log V_x - \log V_m}\right)}\right)^{\frac{1}{a_p}} + \dfrac{V_m}{V_x}\right] \cdot V_x\right\} \times (\psi)}{\left[(\psi) + [1 - (\psi)] \cdot \left[1 - \exp\left(-\left\{\left[\left(\dfrac{1}{N_t} - \left(\dfrac{V_m}{V_x}\right)^{\left(\frac{\log N_x - \log N_m}{\log V_x - \log V_m}\right)}\right)^{\frac{1}{a_p}} + \dfrac{V_m}{V_x}\right] \cdot V_x\right\} \div V_s\right)\right]\right]^S} \tag{2}$$

where:

a_p - slope of straight line approximated from USGS sample points (same as slope of Pareto distribution).
N_m - minimum number of USGS provinces (= 1).
N_t - cumulative number of provinces.
N_x - maximum number of provinces.
S - severity exponent that controls the steepness of the slope of the estimated VSD curve where it separates from the Pareto straight line (on the right tail of the distribution, typically near the largest volumes).
V_m - minimum USGS province volume.
V_s - approximate volume at which the USGS data begins to deviate from the Pareto straight line (on the right tail of the distribution, near the largest volumes).
$\hat{V}_i$ - estimated volume of a province.
V_x - maximum volume (tcf) given by the Pareto straight line (at $N_m = 1$). The actual maximum volume could be larger, equal to, or smaller than V_x.
ψ - separation ratio that controls the amount of separation between the Pareto straight line and the estimated VSD curve (on the right tail of the distribution, near the largest volumes).

Equation 1 shows five parameters of the VSD model that are estimated with nonlinear regression: V_x, a_p, V_s, ψ, and S. They are used to obtain the best possible fit of the sample of provinces for which petroleum endowment data from the USGS [55] exists. The parameters are estimated by examining the coefficients of determination (R^2), comparing the USGS and VSD-calculated endowments, and visually inspecting the curves. The exact same parameter values used to obtain a good fit of the provinces evaluated by the USGS [55] are used to forecast the petroleum endowments of unassessed provinces in the region.

VSD endowment estimates

As discussed above, endowment refers to the sum of known volumes (cumulative production plus remaining reserves) and undiscovered volumes [55]. An example of the VSD results, for conventional gas, is presented in **Figure 11**. The lower curve (black diamonds) corresponds to 136 petroleum provinces, excluding the United States. The corresponding gas endowment of 10200 tcf is estimated by the USGS [55]. The endowment calculated by the VSD model (red continuous line) for the same 136 provinces is also 10200 tcf. When the petroleum provinces of the United States are included, the USGS estimates a gas endowment of 11600 tcf in a total of 216 provinces. This is represented by the middle curve (open circles) in **Figure 11** and is similar to the 11400 tcf calculated by the VSD for the same 216 provinces (pink continuous line). Note that these volumes do not include reserve growth or unconventional gas. Next, the VSD is extended out of sample to generate an estimate of the conventional gas endowment in the 937 petroleum provinces of the world. This application is important because 528 out of the 937 world-wide petroleum provinces had not been evaluated previously. The top curve of **Figure 11** corresponds to 937 provinces where each data point represents a province and the summation of all the points gives a total conventional gas endowment of 15,000 tcf for the world.

Tight gas reservoirs are present in all or nearly all petroleum provinces of the world and occur at very shallow to very great depths. According to [61], the conventional gas endowment of 15000 tcf calculated for 937 petroleum provinces (**Figure 11**) will likely be rivaled by technically recoverable gas from tight formations. In [61], data and experience from North America – and more limited information from other countries – was used to convey the message that knowledge of conventional gas reservoirs can be used as a proxy for the evaluation of unconventional tight gas traps. The proxy was supported by geology, a discovery process analysis, North American comparisons between endowments of conventional and tight gas, and a gas resource pyramid. This message conforms well to Salvador’s qualitative assessment in AAPG Studies in Geology #54 that “although the distribution and magnitude of tight-sand accumulations elsewhere in the world is not well known, it can be said with assurance that large volumes of gas are present in these low-permeability reservoirs.” A similar assessment is provided by [62] who indicates that “tight gas reservoirs are present in almost every petroleum province and occur at very shallow to very deep depth.” Assuming the proxy proposed in [61] is reasonable, **Figure 12** shows a VSD curve for conventional gas plus tight gas. In addition to the estimate of 15000 tcf for conventional gas, and additional 15000 tcf is estimated for tight gas in 937 provinces. This observation lends credence to the notion that where there is conventional gas, there is also tight gas. For the case of CBM, we rely on the estimate provided in the Global Energy Assessment [63], which gives a global CBM endowment of nearly 10000 tcf. This has been incorporated exogenously into the outer curve of **Figure 12**, which adds around 10000 tcf of CBM to the conventional and tight gas total.

The VSD has also been used to estimate the shale gas endowment for the world. A starting point is the resource estimates provided in the study by the US Energy Information Administration and the consultancy Advanced Resources International Inc [64]. Though some might argue the assessment is overly optimistic, others claim it is conservative since it does not consider some regions believed to contain significant endowments (notably, the Middle East). The lower curve in **Figure 13** represents the 48 provinces assessed in [64] and shows an endowment of about 22000 TCF. The VSD model is used to obtain the best possible fit of the sample data for the 48 provinces. As shown in **Figure 13**, the solid VSD line gives a very good fit and also generates a volume of about 22000 tcf. We then extend the VSD to 165 provinces around the world [65] that are thought to contain shale gas, resulting in a volume of about 32000 tcf.

In summary, the total conventional and unconventional gas endowment of conventional gas (~15000 tcf), tight gas (~15000 tcf), CBM (~10000 tcf) and shale gas (~30000 tcf) gives a grand natural gas total of around 70000 tcf.

Supply curves

Supply curves are two dimensional representations of how resource endowments vary with production costs. Upstream production costs are typically composed of capital and operating costs, including a return on capital, though often exclude taxation and royalties due to the significantly different tax regimes across the world. Capital costs are mainly reflective of expenditures on development drilling, processing equipment, production facilities, pipelines and abandonment. Operating costs include mainly field operating costs and transportation costs. External costs, such as those associated with global warming, are usually not considered in cost estimates, largely because there is no consensus on what these costs are despite the considerable efforts by governments around the world to internalize them over the past several decades. Supply curves are useful tools for measuring long term availability as they show both recoverable quantities as well as costs of producing those quantities. If reasonable estimates of gas volumes available at some specified price level appear sufficient to cover estimates of future demand, this provides practical information with respect to the concerns some have expressed about possible shortages in certain parts of the world.

Figure 14 is a supply curve for conventional gas that was initially estimated in [60]. In that study, the conventional gas supply curve used endowment volumes from the USGS (2000) study [55] and attached production costs based on available data. With the use of the VSD, the curve also included volumes from provinces that the USGS (2000) study did not assess. Although difficult to obtain, cost data was sourced from companies’ annual and financial reports, contacts within the industry, trade press journals, intergovernmental agency reports and academic literature. The costs in **Figure 14**, originally for the year 2009, have been inflated by 3% per year to generate an estimate of 2012 costs (based on capital and operating cost indices in [66]). It should also be noted that the costs are static and therefore do not take into account the tendency of technological change and different markets conditions to reduce costs over time and increase future supply. Cumulative historical gas production of about 2000 tcf is not included in the curve.

As discussed earlier, the conventional gas endowment of 15000 tcf has been used as a proxy for gas from tight formations. Thus, the tight gas supply curve in **Figure 15** uses the same supply curve for conventional gas (i.e. **Figure 14**) except that the costs have been increased by 25% to reflect the additional costs associated with tight gas development. In particular, this refers to the use of multi-stage hydraulic fracturing. Existing supply curves comparing generalized costs for various types of formations reveal that the costs of producing tight gas do not exceed those of conventional gas by a siginificant amount [67]. Although simplistic, it appears reasonable to therefore assume that tight gas production costs in **Figure 15** are about 25% higher than conventional gas costs.

The shale gas supply curve in **Figure 16** is constructed by attaching the shale gas production costs estimated in [68] to the endowment quantities estimated by [64] and the VSD model. In this case, it is possible to provide a fairly detailed supply curve given that both the volumetric and cost data are disaggregated according to geological provinces. Thus, the costs for a particular province as estimated by [68] are matched with the estimated volumes of the corresponding province as estimated by [64]. Although the curve shows a wide range of production costs, it is clear that the majority of the endowment can be produced at costs that are comparable to conventional gas costs.

A different approach, akin to the supply curve methodology in [63], is used for the CBM supply curve in **Figure 17**. In this method, several supply categories are defined based on production costs. Each category is assigned a lower and upper bound of costs. The endowment volume is then allocated across the categories in a specified proportion in order to generate the supply curves. For the case of CBM, five production cost categories are used. Based on [67], the costs are also assumed to be in a similar range to those of conventional gas. Distributing our estimated CBM endowment volume of 10000 tcf across the production cost categories leads to the supply curve of **Figure 17**.

To reiterate, one of the main points to be taken when comparing **Figures 14 to 17** is that the production costs of unconventional gas are not significantly higher than their conventional counterparts. Effectively, improvements in technology have reduced the costs of producing unconventionals to the point where, in some instances, these costs are lower than those of conventional gas. Based on this finding and the endowment estimates discussed above, it can be concluded that natural gas quantities are more abundant and economic than commonly assumed.

Environment

Energy consumption by 2035 is estimated at 790 quads and the world population at 8.5 billion [61]. These projections are larger than those of the US Energy Information Administration and the International Energy Agency. The good news is that any one of the projections would easily be met with the endowment of conventional gas, tight gas, shale gas, and CBM. In addition, there are significant economic and environmental advantages to the use of gas for electrical power generation. In the longer term, there is also potential for natural gas vehicles and gas-to-liquids conversion. Advances in gas transportation technologies (e.g. liquefied natural gas) will also aid in globalizing gas markets and thus increase the share of gas in the future energy mix.

Table 1 shows some of the environmental advantages that, in our opinion, natural gas has over oil (and by default coal). However, there are opposing opinions with respect to benefits and costs of natural gas. For example, [69] indicate that “3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.”

On the other hand, [70] indicate that “shale gas life-cycle emissions are 6% lower than conventional natural gas, 23% lower than gasoline, and 33% lower than coal.” [71] conclude that “the GHG emission estimates for Marcellus gas are similar to current domestic gas.” Additionally, there are several other studies showing opposite opinions and conclusions.

As mentioned previously, environmental concerns have also been raised by some commentators about the unsustainable use of freshwater and contamination of aquifers during the fracking process of unconventional gas production. However, advances have been made in the treatment of waste water so that it may be reused, thus alleviating the drain on freshwater supplies. Also, advances in well design and casing cementing prevent the leakage of water or methane from the well.

Another issue has to do with the fracturing process itself, and the nature of fluids employed. If too much pressure is employed, or if the geological stresses are not fully understood, or if the formation is relatively shallow and near a groundwater source, a fracture can extend into the groundwater formation, and there could then be mixing of fluids and gas into the groundwater. Given that most of the shale gas formations are relatively deep and well below groundwater formations, this negative outcome is relatively unlikely. This is supported by real fracture-growth data extracted from microseismic measurements during thousands of hydraulic fracturing treatments performed in unconventional reservoirs [72]. When the top of the vertical growth of hydraulic fractures is compared with the bottom depth of ground water deposits, the conclusion is readily reached that the possibilities of these fractures reaching ground water are very low. The industry has learned far more about how to control the extent and direction of the fractures created. Given that the dominant principal stresses change from vertical (at reservoir depth) to horizontal as the ground surface is approached, the possibilities of any hydraulic fracture connecting with ground water are further diminished.

Hundreds, if not thousands, of chemicals are included in the fluids injected. But it is frequently ignored that these chemicals typically make up less than 3% (typically now under 1%) of the fluids injected. The particular mix of water, sand (which is included to help hold the fractures open once the fluid is withdrawn from the well), and chemicals is designed to enhance the flow of natural gas from the well. If the appropriate procedures are followed by the operator, none of these chemicals should find their way into the groundwater.

As society will require increasing energy in the future, the use of natural gas should be encouraged as this is the cleanest fossil fuel available (i.e. cleaner than oil and coal). Nevertheless, there is also the problem of contamination of the atmosphere by CO2 and methane. However, it is water vapor that contributes the most to the green house effect (or radiative power) at approximately 60% as compared with 20% contributed by carbon dioxide (CO2) and 20% by a combination of methane (CH4), ozone (O3), nitrous oxide (N2O) and other components. The National Aeronautics and Space Administration (NASA) has indicated that "water vapor is known to be Earth's most abundant greenhouse gas, but the extent of its contribution to global warming has been debated. Using recent NASA satellite data, researchers have estimated more precisely than ever the heat-trapping effect of water in the air, validating the role of the gas as a critical component of climate change… Water vapor is the big player in the atmosphere as far as climate is concerned." [73]

To summarize, if the proper procedures are followed, the economic and environmental benefits of tight gas, shale gas and CBM will likely far outweigh any additional cost associated with such compliance [74].

Discussion and Conclusions

There is a significant endowment in conventional gas accumulations (15000 tcf) that is rivaled by the potential tight gas endowment, also estimated at 15000 tcf. Shale gas has been estimated at 30000 tcf, while CBM is estimated at 10000 tcf. As indicated previously, natural gas hydrates are also part of the unconventional gas group but they are not considered explicitly in this paper given the wide spread of available quantitative estimates. Kvenvolden [75] has compiled best estimates that range from 19600 to 941000 tcf. This leads us to conclude that the total conventional and unconventional gas endowment has the potential to contribute significantly to global energy demand that is projected to reach 790 quads by 2035. As shown in Table 2, there is enough natural gas to supply the energy market for nearly 400 years at current rates of consumption and 110 years with a growth rate in production of 2% per year. However, the economic and technical challenges involved in the commercialization of this vast untapped resource are many. Overcoming the challenges will depend on a multi-disciplinary approach that integrates geoscience, engineering and economics. The cornerstone of the whole project is the proper geologic understanding of the rocks. This must be integrated with development of a correct, environmentally-benign hydraulic fracturing procedure. Although the probabilities of hydraulic fractures reaching ground water are very slim, we anticipate that concerns over environmental pollution by fracturing fluids and methane emissions will continue to provide impetus for improvements in drilling and completion methods as well as the usage of the cleanest fossil fuel of all: natural gas.

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Table 1. Differences and general advantages of natural gas versus oil

Differences	Characteristics	Natural Gas	Oil
Geological:			
	Source rock (kitchen)	Larger	Smaller
	Rocks	Conventional and unconv	Conventional and unconv
	Deep basins HC volume	Large	Smaller window
	Geographic distribution	Wide	Narrower
	Ubiquitous	More	Less
	Pore throat required for flow	Lower	Larger
	Permeability required for flow	Lower	Larger
	Exploration to date	Moderate	Large
Technological:			
	Complexity	Less	More
	Horizontal drilling	About the same	About the same
	Fracturing in conv reservoirs	About the same	About the same
	Fracturing in tight and shale	More complex	More complex
	Surface installations	Simpler	More complex
	Urban smog	Smaller	Larger
	Grid in cities	Large	Nil
	Home/office heating	Large	Small
	Transportation use	Increasing	Clearly dominant
Physical:			
	Odor	No	Yes
	Weight	Light	Heavier
	Compressible	Yes	Slightly
	Depth	Shallow to deep	Narrower
	Flow in rocks	Easier	More difficult
	Extraction	Easier	More difficult
	Recovery	Higher	Lower
	Global diversity	Higher	Narrower
	Environmental damage	Lower	Higher
	Presence in Universe	Beyond earth	Only in earth
Chemical:			
	Chemistry	Simple	Complex
	Formula	CH_4	Complex
	H/C ratio	Lower	Higher
	Refining complexity	Lower	Higher
	CO_2	Lower	Higher
Environmental:			
	Carbon intensity	Less	More
	CO_2 intensity	Less	More
	Damage to environment	Smaller	Larger
	Accident damage	Less	More
	Accident containment	Easier	More difficult
Economics:			
	Price	Lower	Higher
	Resource	Larger	Smaller
	Global market share	Increasing	Peaked in the 70's
	Capital intensity	Smaller	larger
	History	Shorter	Longer
	Production	By-product of oil & unconv	Searched actively

Table 2. Life Expectancies [60].

1	2	3	4			5
Commodity	Future [a] Volumes	2007-2009 [b] Average Annual Production	Life Expectancy in Years, at Various [c] Growth Rates in Production			Average Annual [d] Growth in Production, 1979-2009 (%)
			0%	2%	5%	
Conventional Gas, Tight Gas, Shale Gas, Coalbed	4.22E+16	1.06E+14	**398**	**110**	**61**	2.51
Conventional Oil	3.50E+12	2.96E+10	**118**	**61**	**39**	0.67
Heavy Oil, Oil Sands, Oil Shale	2.30E+13	2.96E+10	**777**	**140**	**74**	-

Notes:
a. Conventional oil, heavy oil, oil sands and oil shale in barrels; conventional gas, tight gas, shale gas and coalbed in cubic feet

b. Average annual production comes from British Petroleum (2010)

c. Life expectancies estimated by this study

d. Average annual growth in production calculated from British Petroleum (2010)

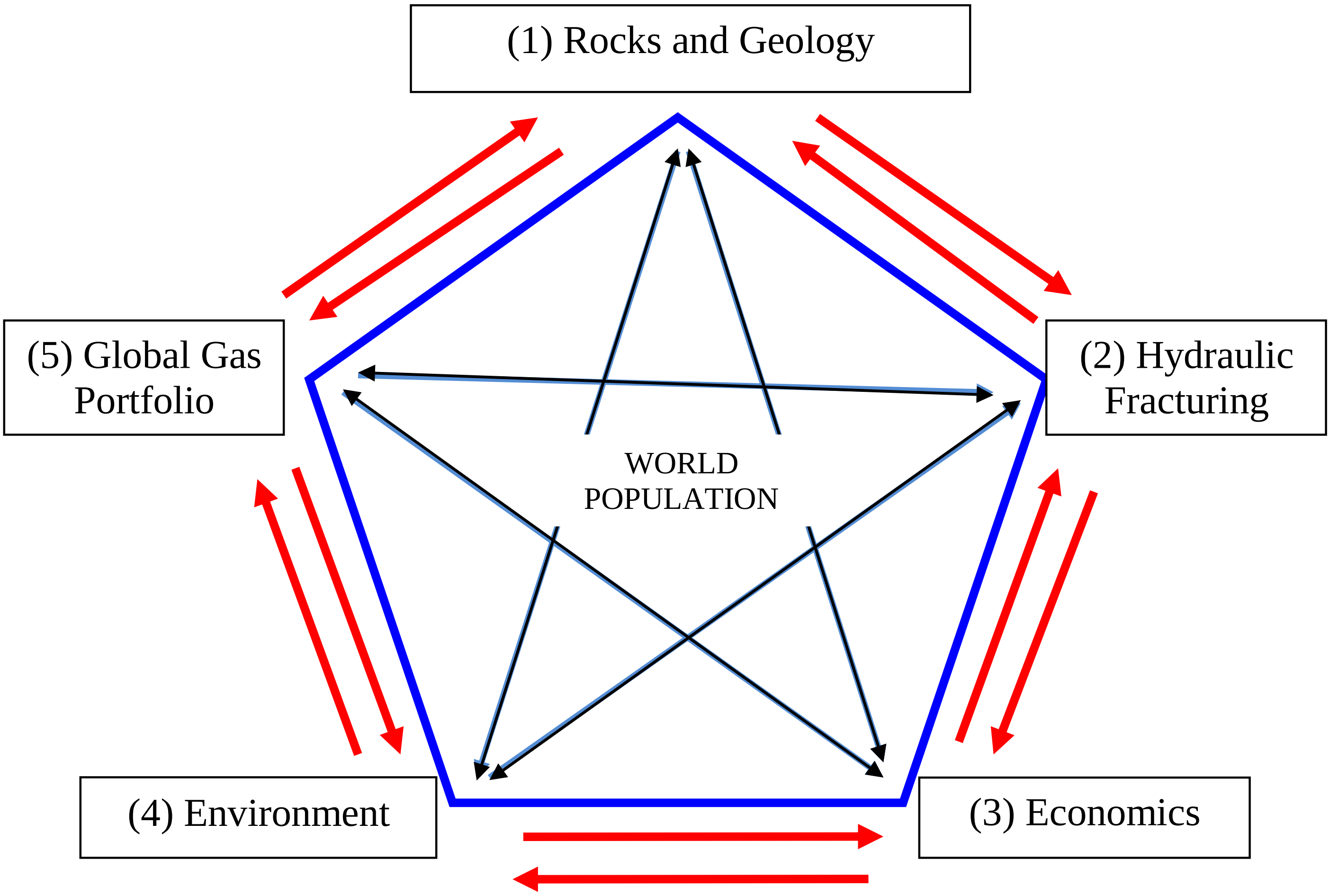

Figure 1. Link between rocks, hydraulic fracturing, economics, environment, and the global gas portfolio. There has to be equilibrium between the 5 corners of the pentagon to provide a win-win situation for society at large.

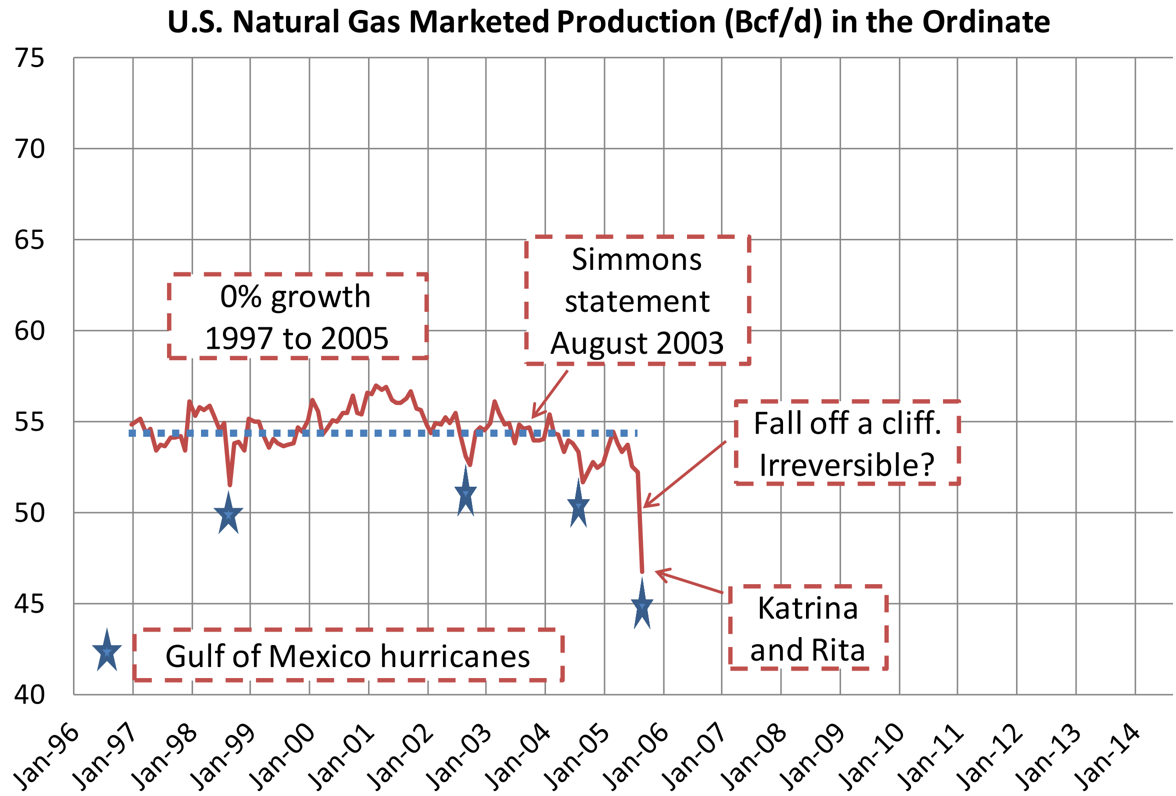

Figure 2A. Pre-2006 actual natural gas marketed production in the United States (data from EIA).

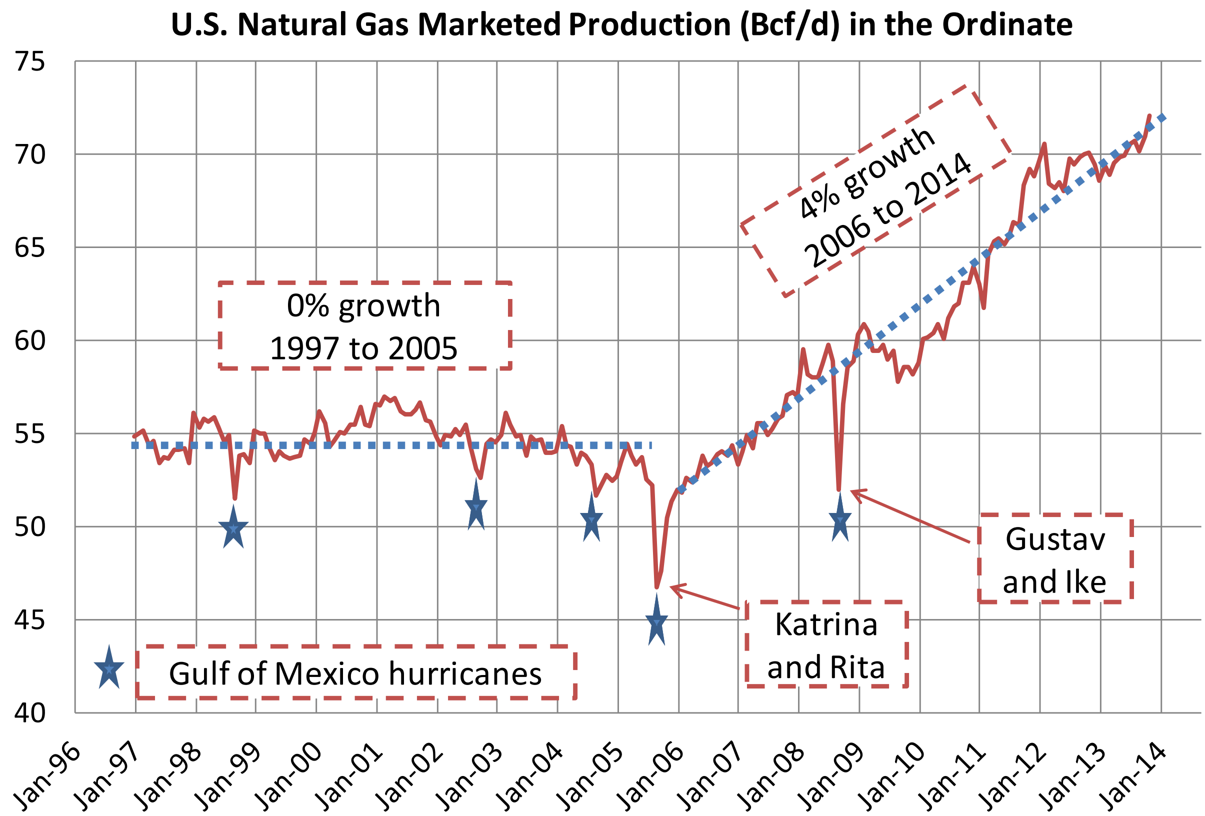

Figure 2B. Post-2006 actual natural gas marketed production in the United States shows a mirror image of the 2003 forecast with a significant increase in production (data from EIA).

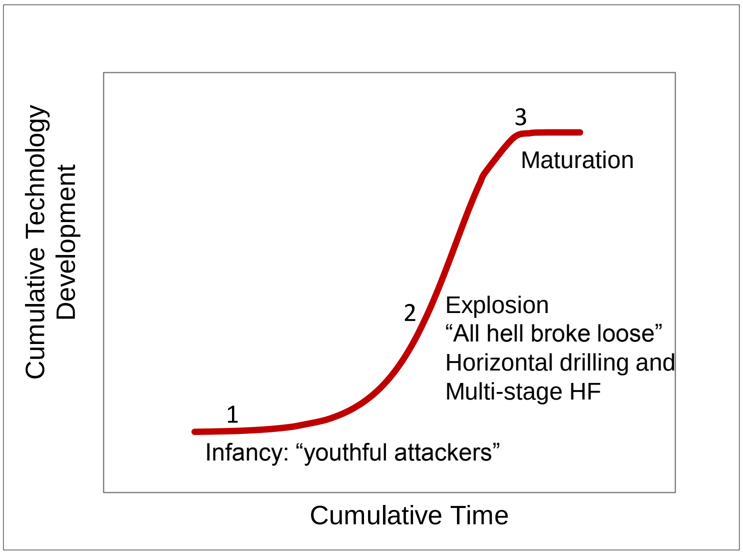

Figure 3A. Foster S-curves for (1) infancy, (2) explosion and (3) maturation of technological progress associated with unconventional gas in the US [3].

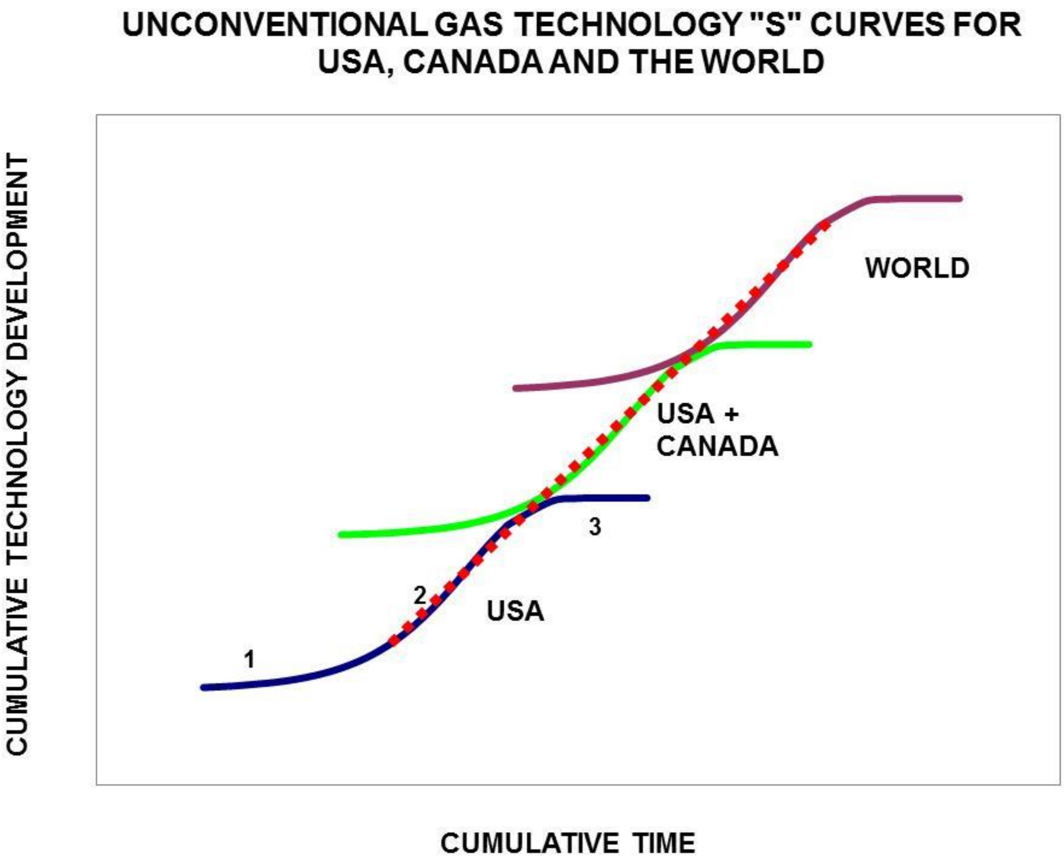

Figure 3B. Integrated Foster S-curves for the US, Canada and the world. The individual curves converge into a single curve that includes the infancy, explosion and maturation of global technological progress and innovation for unconventional gas [3].

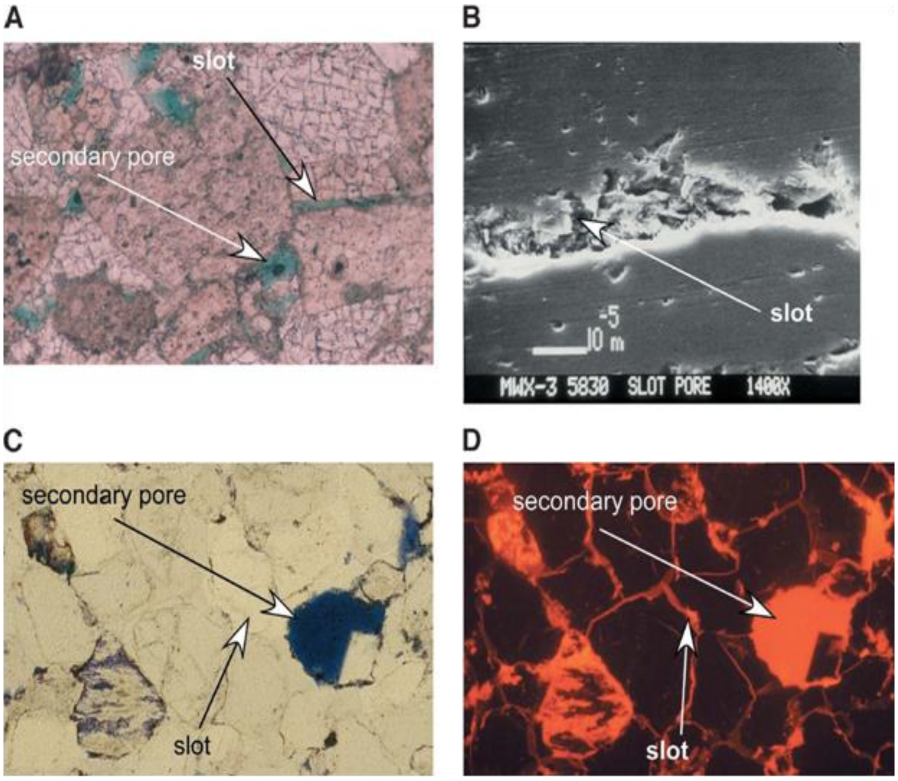

Figure 4. Photomicrograph and scanning electron microscope images illustrating slot-type pores and pore throats commonly found in low-permeability reservoirs [23].

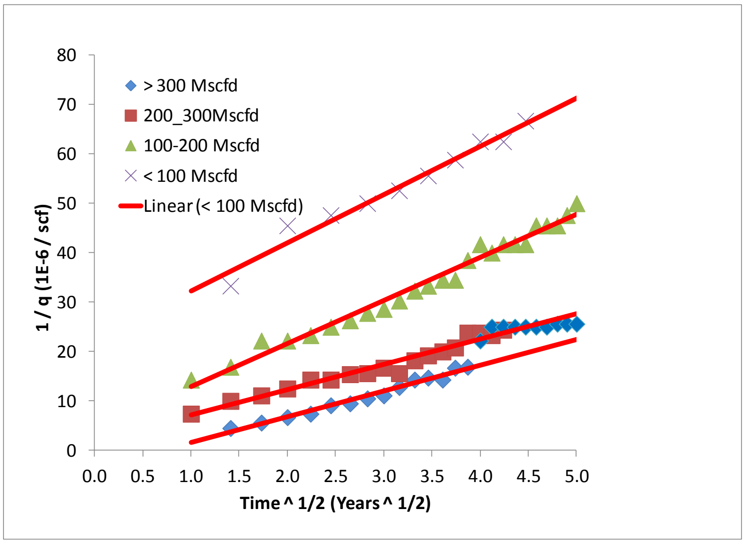

Figure 5. Drawdown linear flow for wells producing from Devonian shales connected fractures in an infinite-acting reservoir. The flow rates extend over a 25-year period without reaching the boundary dominated flow [33].

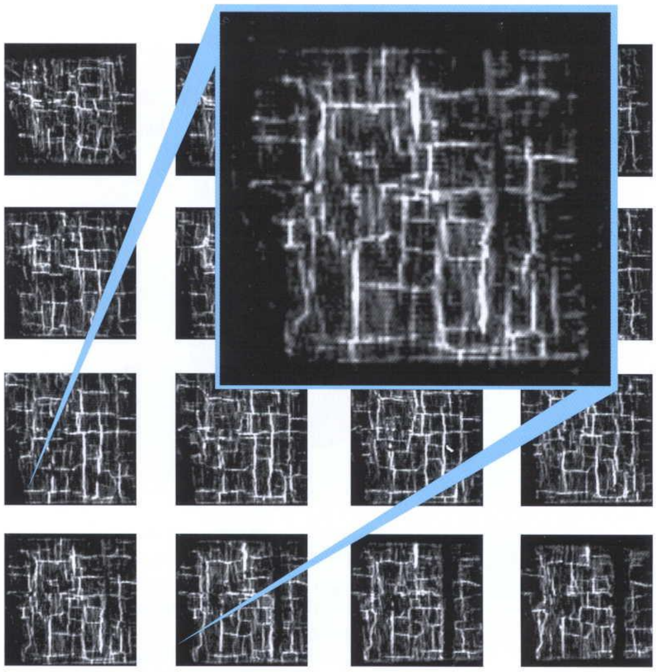

Figure 6. The MRI scans core samples in thin slices, sometimes as thin as one millimeter. In the above 16-image sample of coalbed methane, the cleat system is clearly visible as white lines, allowing an estimate of fracture spacing. The signal arises from imbibed water (Courtesy of Alberta Research Council, Canada).

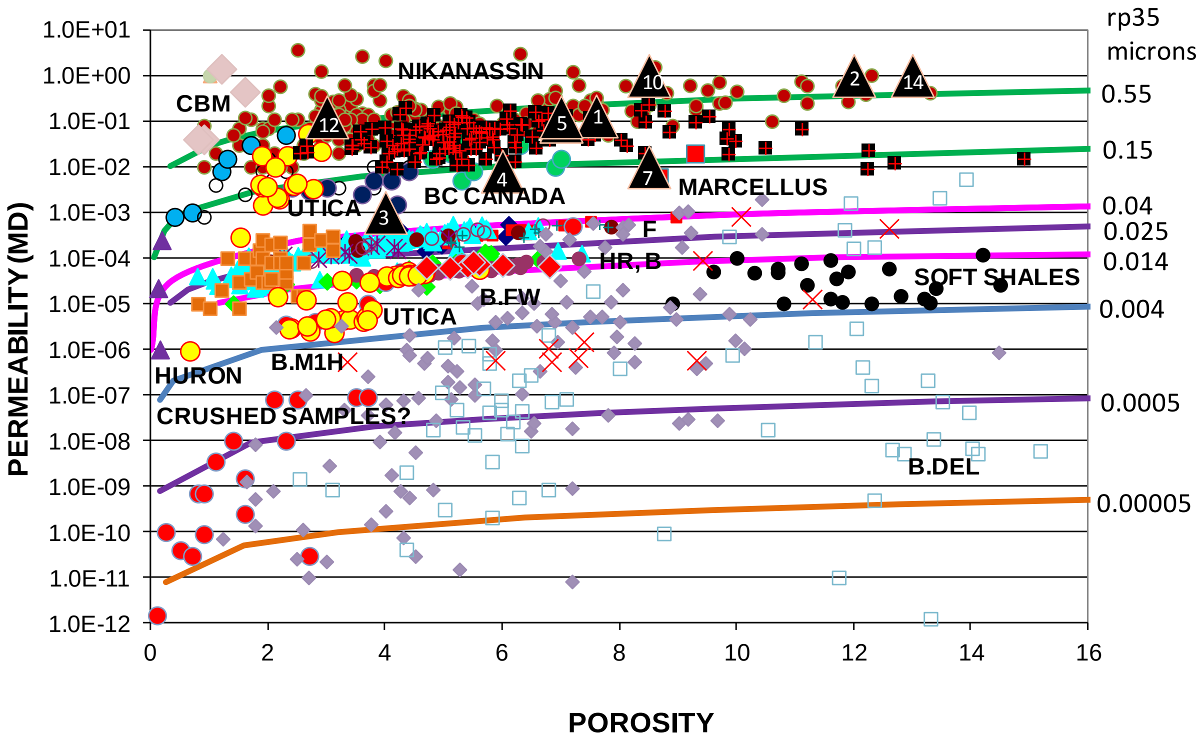

Figure 7. Flow units. Permeability vs. porosity crossplot including data from the Nikanassin tight gas formation (red dots in the upper part of the graph), the Utica shale (yellow circles), Horn River (HR) and soft shales in Canada; Fayettville (F) and Barnet (B) shales in the United States. Additional data include open circles, dark and light blue dots representing plug data from BC, Canada [29]; purple triangles representing Huron shales, and red squares the Marcellus shales [26] in the United States. Black triangles are Middle East and North Africa tight sandstones. Red diamonds are shales from the Perth basin. Big diamonds in the upper left hand corner are CBM samples. Crushed samples are generally below 1E-06 md (Adapted from [30]).

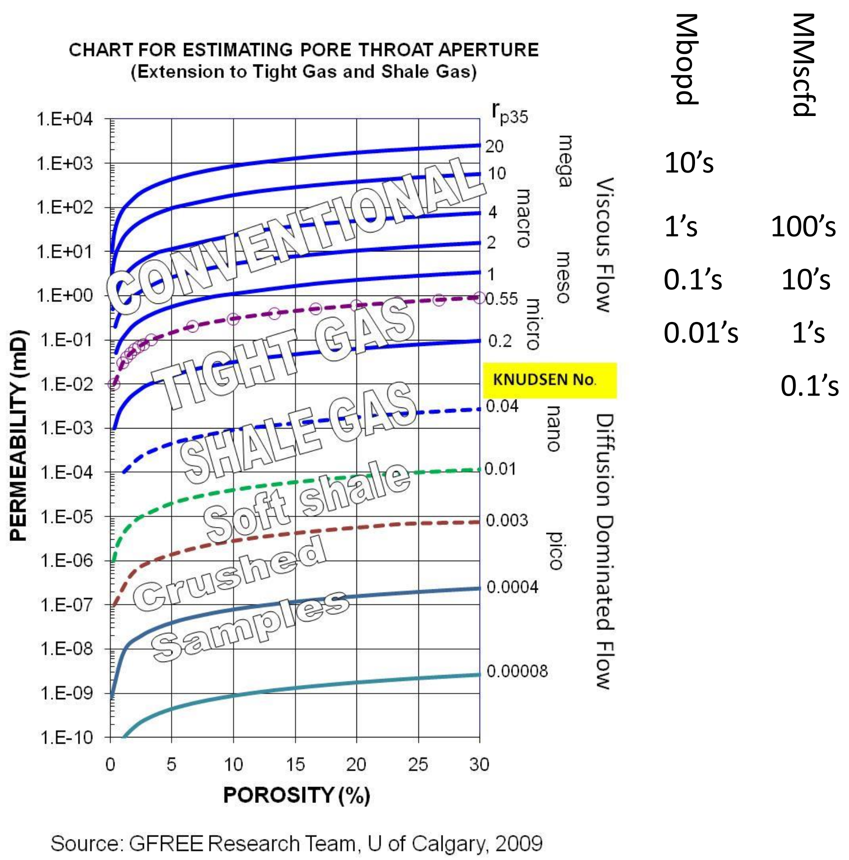

Figure 8. Flow units as a function of pore throat apertures (rp35), porosities and permeabilities and possible ranges of oil (thousands of bopd) and gas flow rates (millions of scfd) for different pore throat apertures [51].

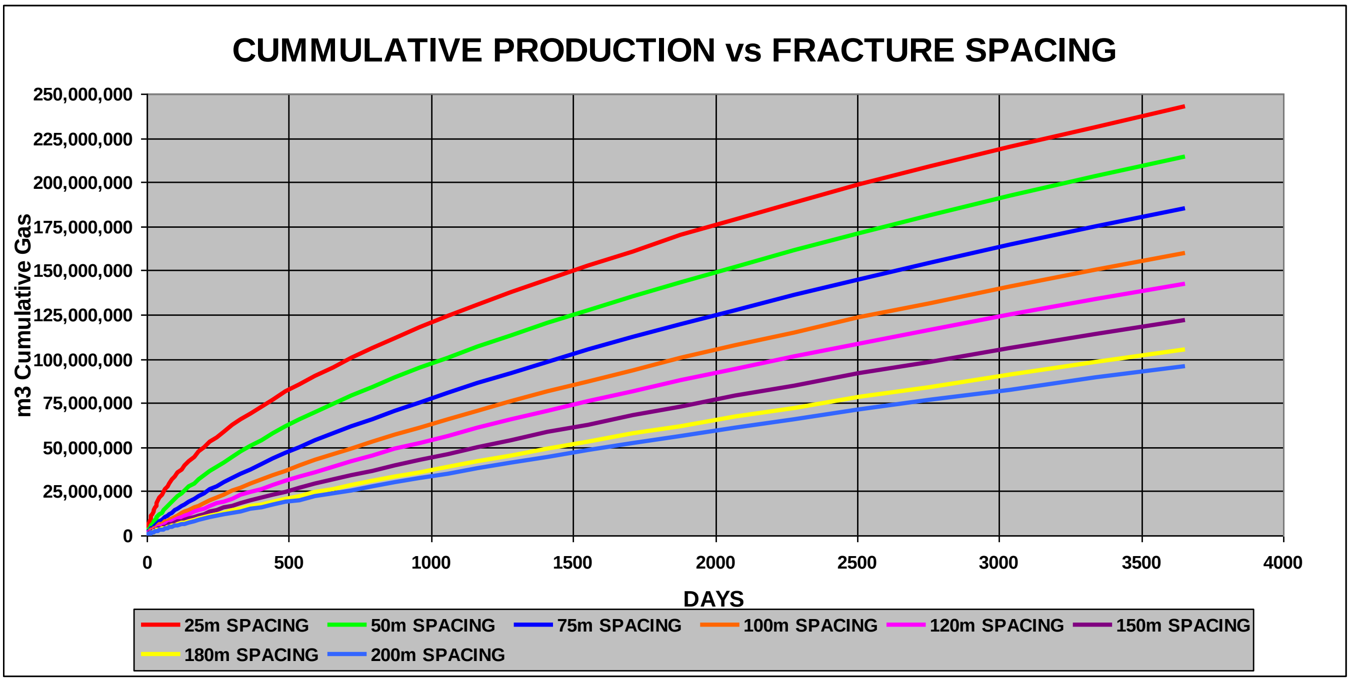

Figure 9. Ten-year cumulative gas production vs. fracture spacings [53].

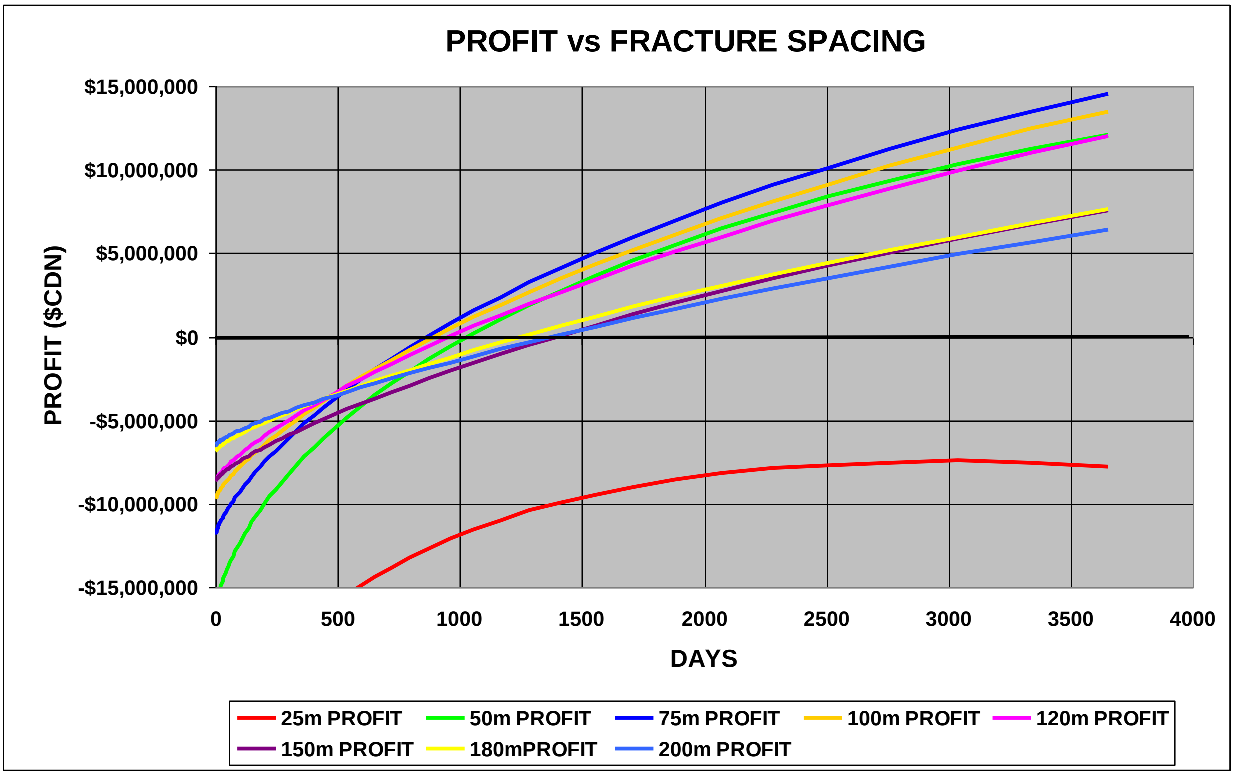

Figure 10. Ten-year profit vs. time (days) for different fracture spacings [53].

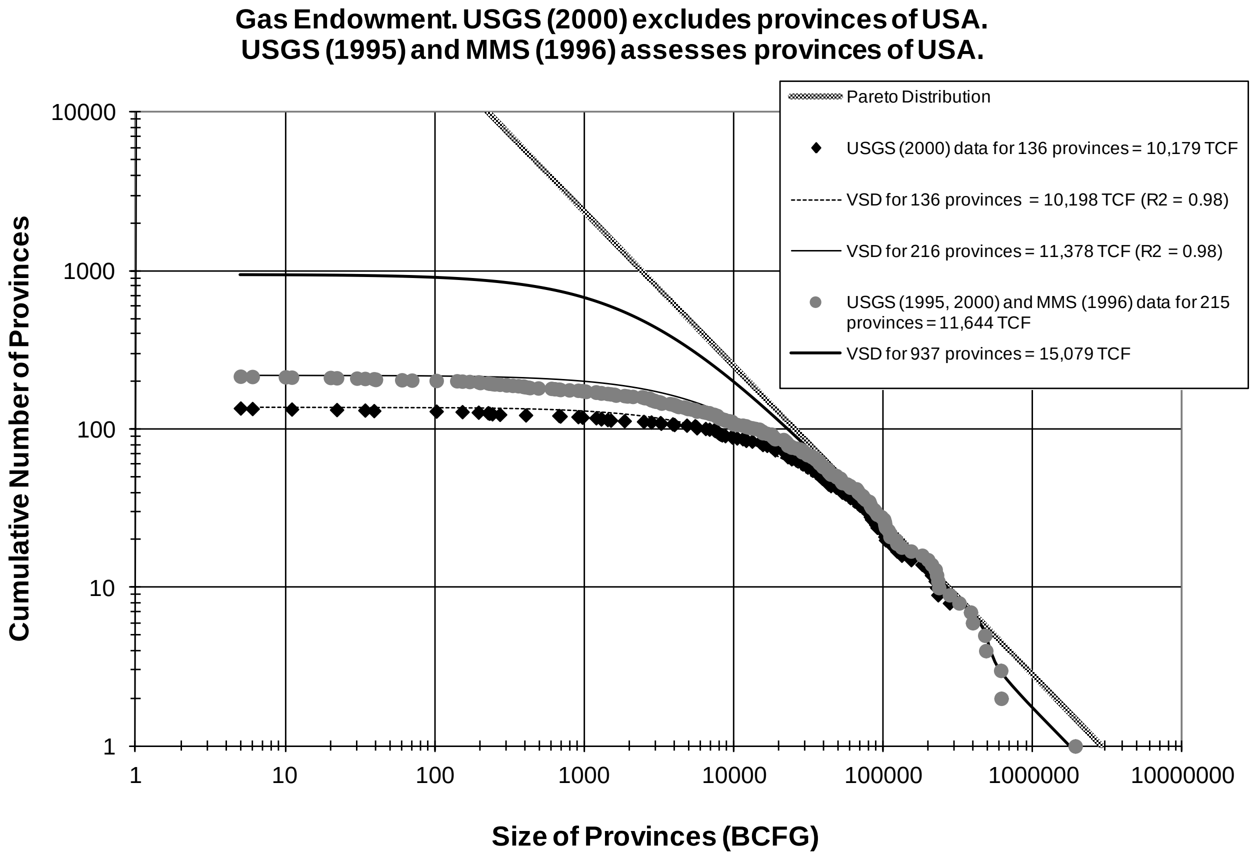

Figure 11. VSD for conventional gas endowment [54].

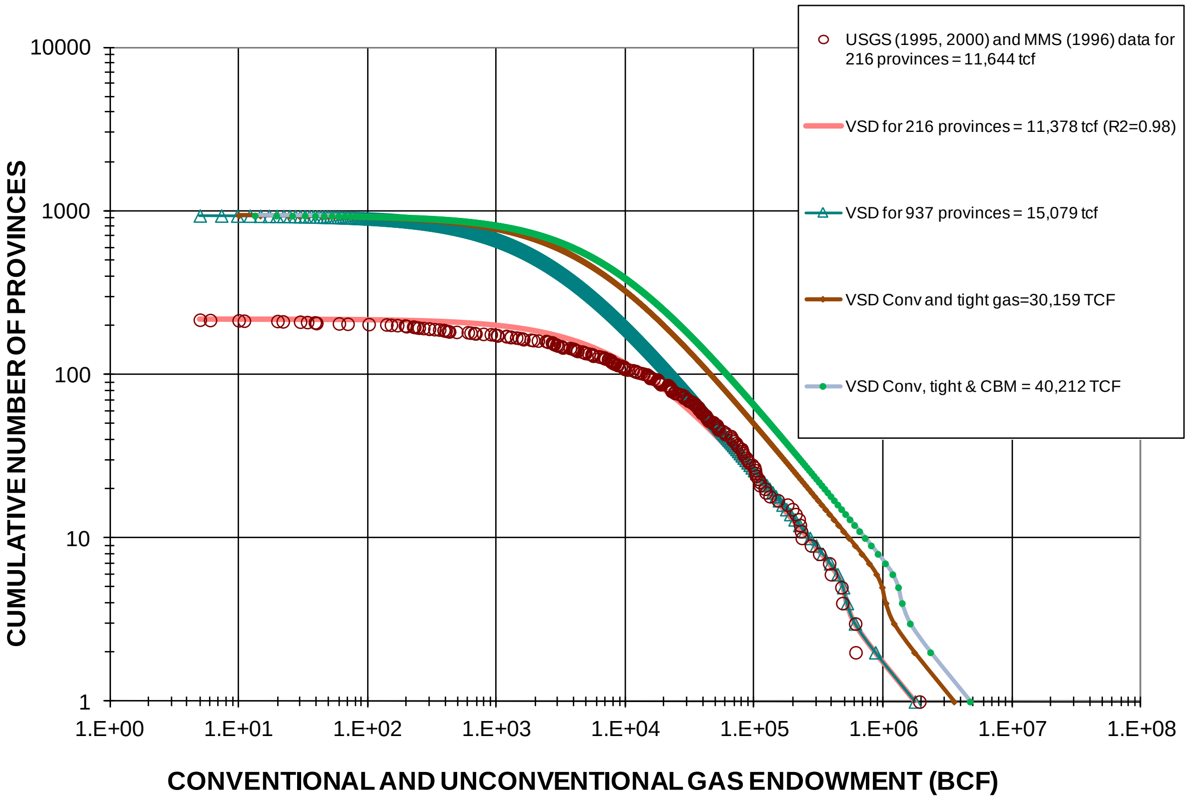

Figure 12. VSD for conventional, tight, and CBM gas endowments as estimated in this study.

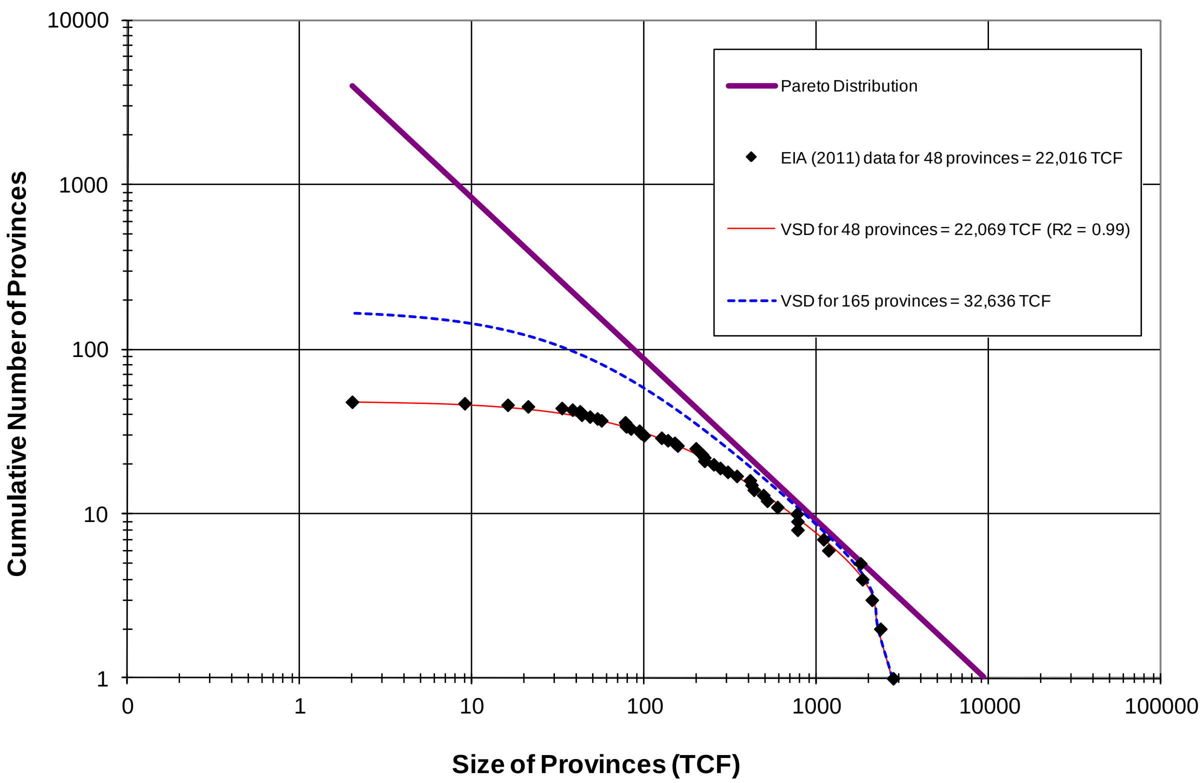

Figure 13. VSD for shale gas endowment as estimated by this study.

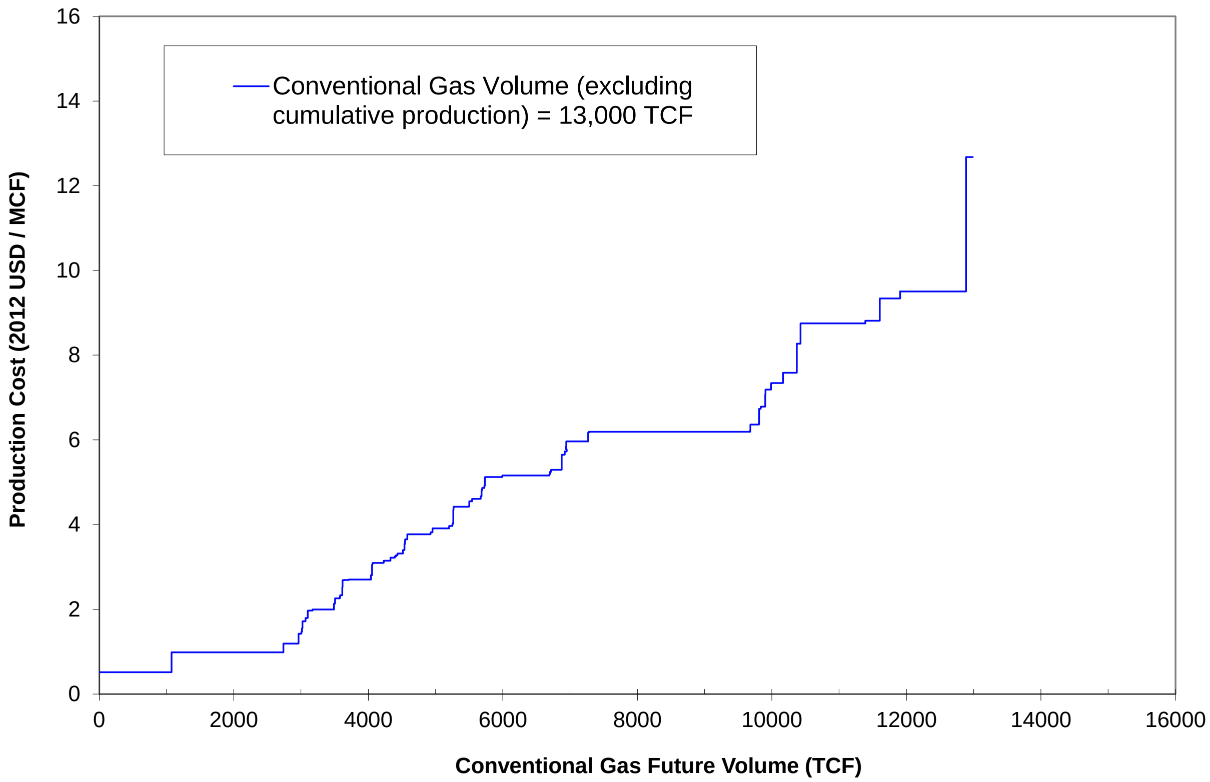

Figure 14. Supply curve for conventional gas.

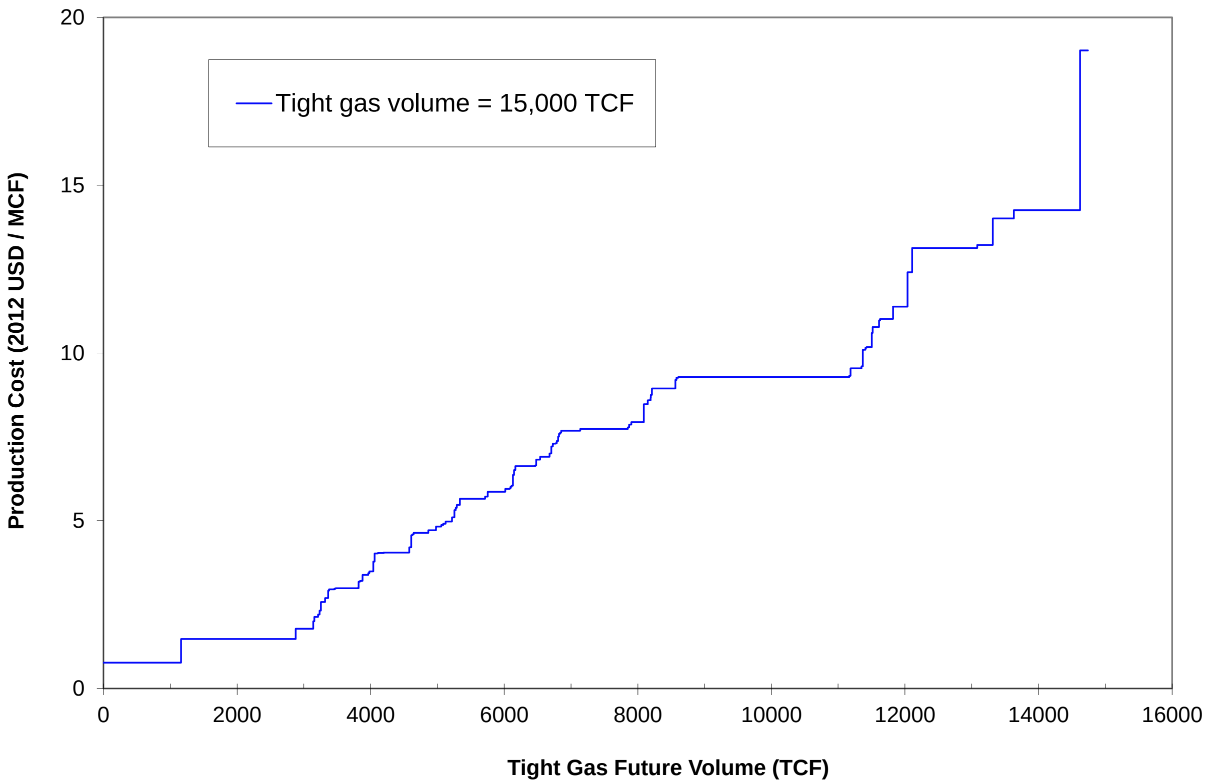

Figure 15. Supply curve for tight gas.

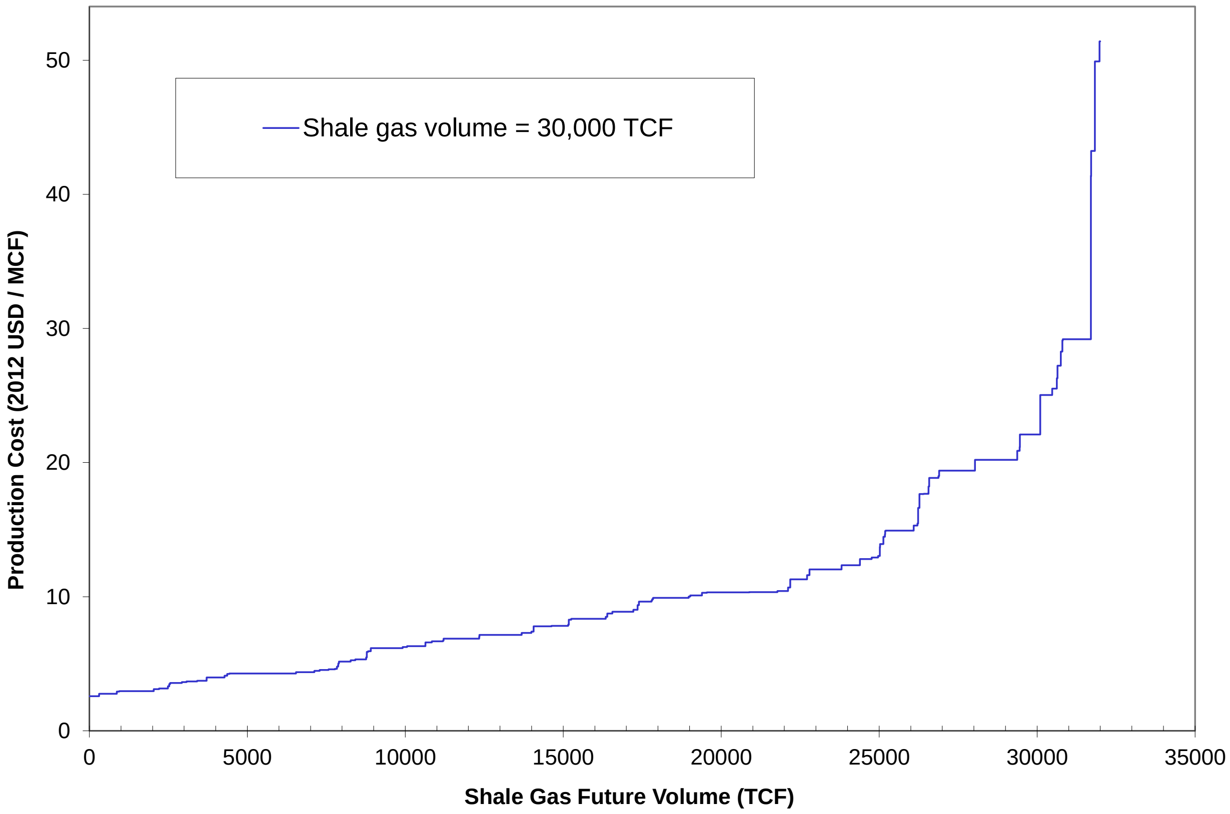

Figure 16. Supply curve for shale gas.

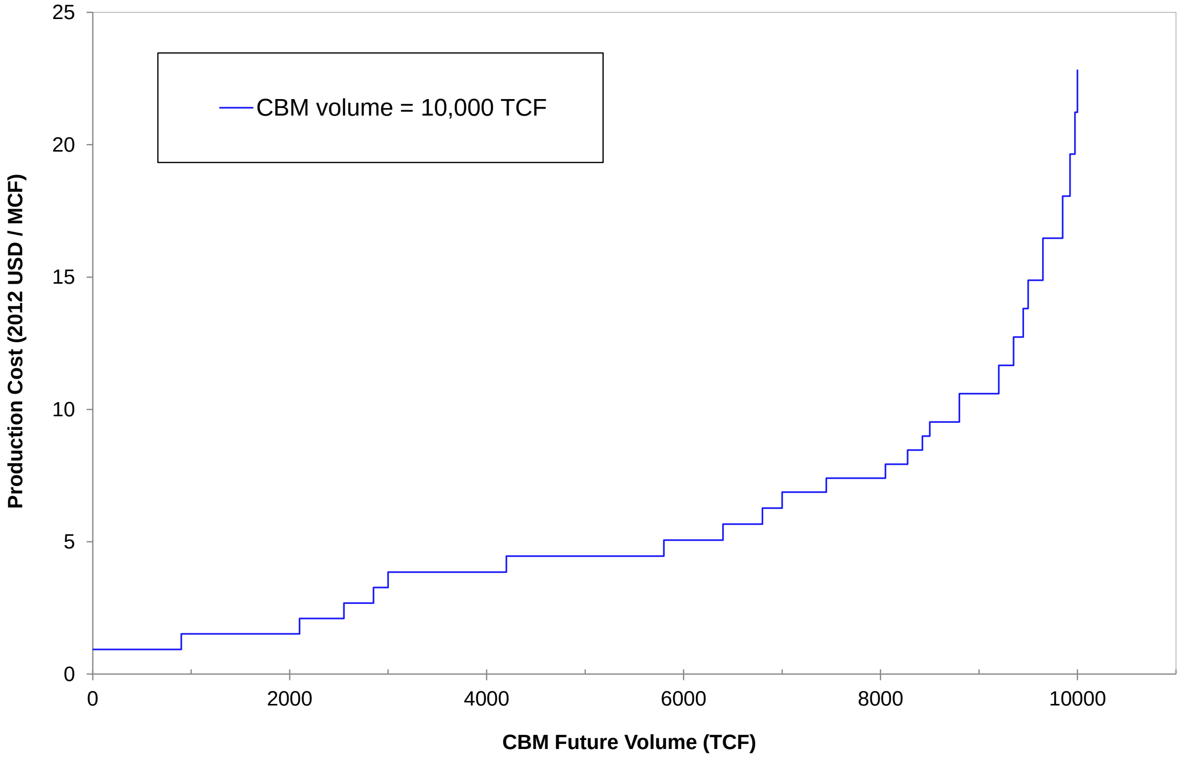

Figure 17. Supply curve for CBM.