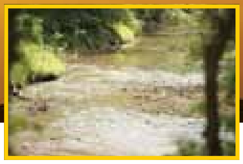

Getting the Gas Out of the Ground

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Technologies developed in the oil and gas industry over the past 60+ years are now being used to produce shale gas.

Until recently, most natural gas came from what are known as conventional reservoirs. This conventional gas is typically trapped in multiple, relatively small, porous zones in rock formations such as sandstones, siltstones, and carbonates. Such gas is relatively easy to recover.

Unconventional gas, on the other hand, is obtained from low-permeability reservoirs in coals, tight sand formations, and shales. These accumulations of gas tend to be diffuse and spread over large geographical areas. As a result, unconventional gas is much more difficult to extract.

An individual well in an unconventional gas reservoir produces less gas over a longer period of time than a well in a conventional reservoir, which has a higher permeability. Thus, many more wells must be drilled in unconventional gas reservoirs to recover a large percentage of the original gas in place (the amount of gas in the formation before any wells have been drilled and produced, OGIP) than are needed for a conventional reservoir.

To optimize production from an unconventional gas reservoir, a team of geoscientists and engineers must optimize the number of wells drilled, as well as the drilling and completion procedures for each well. Often, more data (and more engineering manpower) are required to understand and develop unconventional gas reservoirs than are required for higher-permeability, conventional reservoirs.

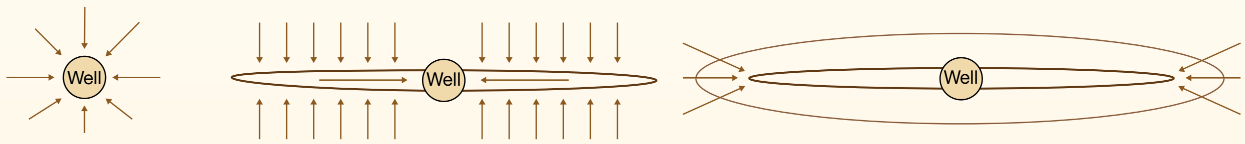
Usually, vertical wells in an unconventional gas reservoir must be stimulated to produce commercial-scale volumes at commercial-scale flowrates. This normally involves a large hydraulic fracture treatment (discussed later). In some unconventional gas reservoirs, horizontal and/or multilateral wells must be drilled, and these wells also need to be fracture-treated.

Improvements in horizontal drilling techniques combined with improved hydraulic fracturing methods have enabled the development of shale gas reservoirs. Neither of these technologies is new. In fact, the combination of horizontal drilling and water fracturing was used extensively in the 1990s in the Austin Chalk formation in Texas.

This article discusses the use of horizontal drilling and hydraulic fracturing in the production of shale gas, some of the key reservoir data needed to determine gas reserves, and the economics of shale gas development.

Changing the reservoir flow pattern

The key to successfully developing any unconventional gas reservoir is to change the flow pattern in the reservoir (Figure 1). In tight gas sands with vertical wells, the flow pattern is altered by pumping large fracture treatments. Simi-



▲ **Figure 1.** Fracture treatment changes the gas flow pattern in a reservoir.

larly, the horizontal wells drilled in shale gas reservoirs need to be fracture-treated to connect the reservoir to the horizontal borehole and to create a network of flow paths.

Figure 1 illustrates how the radial flow pattern characteristic of vertical wells is changed to linear and finally elliptical flow for reservoirs containing either a horizontal wellbore or a long hydraulic fracture.

Horizontal drilling

The horizontal well is the key to changing the flow pattern in the reservoir. It is common to drill horizontally to a distance of 3,000–10,000 ft in length and perform 10 to 30 fracture stages down the length of the wellbore. In many reservoirs, the horizontal wellbore length is about 5,000 ft.

Directional drilling (*i.e.,* the drilling of wells at multiple angles) has been used for over 60 years to develop offshore fields. For a typical onshore well, the drilling rig is located directly above the reservoir target. However, for offshore wells drilled from a fixed platform (and for multiple shale gas wells drilled from a single pad), the wells need to be drilled directionally to reach their reservoir targets.

Beginning in the early 1980s, horizontal wells became a common technology used to develop unconventional resources. The gain in productivity realized by horizontal wells over vertical wells ushered in a new era of development. Increasing exposure to the pay zone (the zone containing gas) and changing the flow pattern in the reservoir allowed many marginal reservoirs to be economically developed. In many cases, the production of oil and gas increased by factors of three to ten compared to vertical wells, while the costs increased by a factor of two or less.

An important breakthrough in directional drilling was the mud motor. Also known as a positive-displacement motor (PDM), the mud motor is a positive-displacement pump that uses the flow of drilling fluid (mud) to turn the drill bit. This rotation at the bit is independent of the rotation of the drill string (the column of pipe that transmits drilling mud and torque to the bit). By pairing the downhole mud motor with a bent sub (an angled section of drill string) above it, the directional driller is able to steer much more effectively.

The PDM has been the standard for drilling directional wells since its introduction, and is still the most commonly used directional drilling tool, both in the U.S. and worldwide. However, a new technology — rotary steerable systems — represents a step-change in downhole directional-drilling technology. Rotary steerable systems eliminate the need to slide the motor to make course corrections and allow the driller to correct the well path while the drill string is being rotated.

Hydraulic fracturing

In hydraulic fracturing, a mixture of hydraulic fluid and propping agents is pumped at high pressure into the well bore. The hydraulic pressure creates artificial fractures in the reservoir and causes the fractures to grow in length, width, and height. Hydraulic fracture treatments are applied to alter the flow pattern in the reservoir.

Figure 2 illustrates schematically how a fracture treatment is conducted. The fracturing fluid is usually water mixed with additives to control viscosity, pH, and other physical characteristics (discussed later). A blender mixes the fluid with a propping agent (usually sand) and various other additives, and supplies the fracture fluid slurry to high-pressure pumps. The main fracturing pumps increase the pressure from a few hundred psi to over 20,000 psi, depending on the depth of the formation and the friction pressure in the wellbore.

Initially, the fracture fluid is pumped into the reservoir without any propping agent (proppant). The high-pressure fluid cracks the rock in the pay zone, pushing the earth apart so a fracture forms and propagates. The cross-hatched area in Figure 2 represents the fracture area. When the fracture is wide enough, the propping agent is blended into the fluid and the slurry is pumped into the well. The area of the fracture containing proppant is referred to as the propped fracture area. Once the fracture fluid pumping is completed, the hydraulic fracture stops growing, and the areas without proppant close.

Gas flows into the wellbore only through the propped fracture area that cleans up (*i.e.*, the area where the long-chain molecules responsible for the fluid's viscosity break into smaller molecules, reducing the viscosity). This allows the fluid to flow from the fracture into the formation or down the fracture to the well-

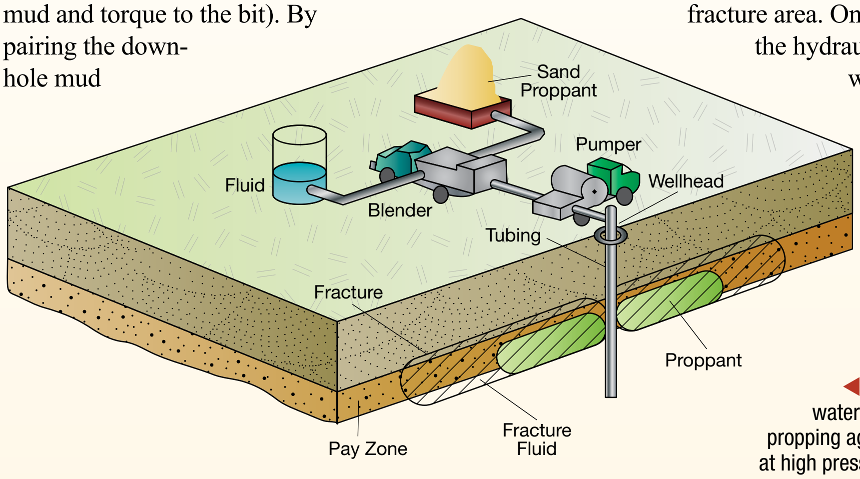


Figure 2. In a typical hydraulic fracturing operation, water containing trace amounts of additives is mixed with a propping agent (usually sand), and the resulting slurry is pumped at high pressure into the well.

bore. If the long-chain molecules do not break (for example, due to increased temperature or a chemical reaction), the fluid will remain in the fracture and natural gas will not be able to enter the fracture and flow to the wellbore. Incomplete fracture-fluid breaking can cause a reduction in gas flowrate and gas recovery.

Fracture treatments in shale gas reservoirs appear to create a network of many fractures that propagate simultaneously, some of which are propped open and others that are not. The fracture network results in the desired stimulation of gas flow in many shale formations. Most engineers believe that the non-propped fractures contribute to the productivity, although it is not clear how much of the gas flow is associated with the non-propped fractures.

Figure 2 is a simple schematic representation. In reality, pumping a large fracture treatment is much more complicated, and involves numerous fracture tanks, blenders, pump trucks, and more, as shown in Figure 3. The capital costs of these fracture treatment spreads are substantial, as are the manpower needed to pump the treatments and the associated labor costs.

Designing a fracture treatment

To predict gas flowrates and ultimate gas recovery and to design the well completion (the steps taken to transform a drilled well into a producing well), the engineer employs a reservoir model, a hydraulic fracture propagation model, and an economic model. The design process involves determining whether to drill a horizontal wellbore, and if so, its location in the reservoir and its length. Fracture-treatment details include the number of stages (*i.e.,* pumping operations conducted in a portion of the horizontal hole), the desired fluid volume per stage, and the injection rate. The engineer must measure or estimate the formation depth, formation permeability, *in situ* formation stresses in the pay zone, *in situ* formation stresses in the surrounding layers, formation modulus, reservoir pressure, formation porosity, formation compressibility, and the thickness of all the reservoir layers.

Vertical profiles of rock properties. To design the well path and the fracture treatment using either a multilayer reservoir model or a pseudo three-dimensional (P3D) hydraulic fracture propagation model, data on the rock properties of all the layers through which the fracture treatment will be pumped are needed. Figure 4 summarizes some of the important input data required by these models for a typical well.

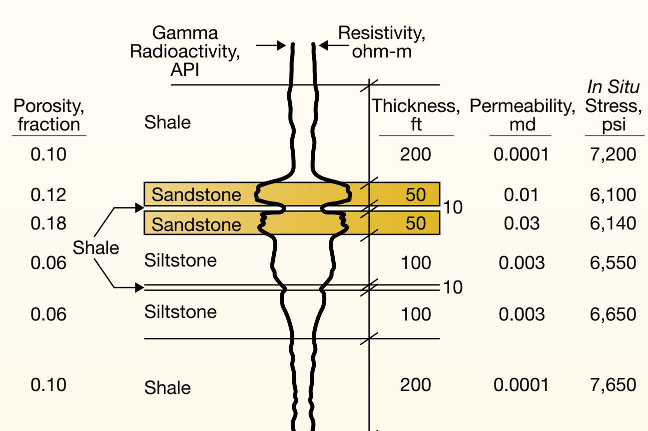
The well depicted in Figure 4 is completed and the fracture treatment is initiated in the sandstone reservoir. A fracture typically grows upward and downward until it reaches a barrier that prevents vertical fracture growth. Thick marine shales, which tend to have higher *in situ* stresses than the sandstones, and highly cleated coal seams, which contain many natural fractures running in different directions that trap the fracture fluid, often serve as barriers to fracture growth.

The data used to design a fracture treatment can be obtained from various sources, such as drilling records, completion records, well files, open hole logs, cores and core analyses, well tests, production data, geologic records, published literature, etc. Table 1 summarizes the most important data and the most likely sources of the information. In addition, well service companies provide data on their fluids, additives, and propping agents.

One of the most difficult and time-consuming responsibilities of a petroleum engineer is to develop an accurate and complete data set for the well to be drilled. Once an accurate data set is available, the actual design of the well and the fracture treatments is fairly straightforward.

Fracture fluid selection. A critical design decision is the selection of the fracture fluid for the treatment. In shale gas

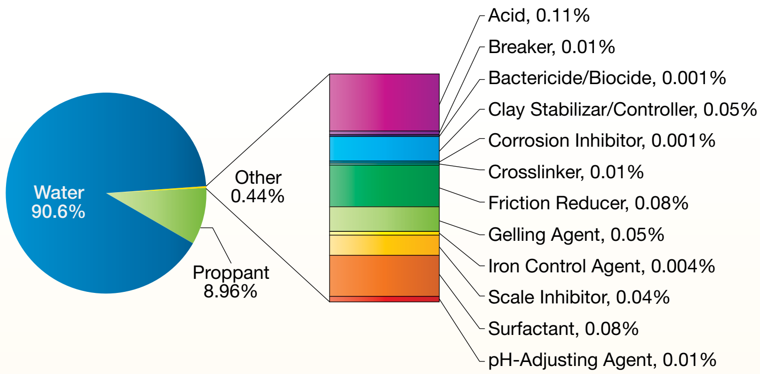
▲ **Figure 3.** Pumping a fracture treatment involves many tanks, blenders, pump trucks, and other equipment. Photo courtesy of Halliburton.



▲ **Figure 4.** Data such as gamma ray radioactivity, porosity, resistivity, permeability, and *in situ* stress need to be collected for each layer of rock.

Table 1. Data for reservoir and fracture-propagation models come from numerous sources.			
Parameter	**Units**	**Model***	**Sources**
Formation permeability	md	R, F	Cores, well tests, production data
Formation porosity	%	R, F	Cores, logs
Reservoir pressure	psi	R, F	Well tests, well files, regional data
Formation depth	ft	R, F	Logs, drilling records
Formation temperature	°F	R, F	Logs, well tests, correlations
Water saturation	%	R, F	Logs, cores
Net pay thickness	ft	R, F	Logs, cores
Gross pay thickness	ft	R, F	Logs, cores, drilling records
Formation lithology		R, F	Cores, drilling records, logs, geology
Wellbore completion		R, F	Well files, completion prognosis
Reservoir fluids		R	Fluid samples, correlations
Relative permeability		R	Cores, correlations
Formation modulus	psi	F	Cores, logs, correlations
Poisson's ratio		F	Cores, logs, correlations
In situ stress	psi	F	Well tests, logs, correlations

* R = reservoir model, F = fracture-propagation model



▲ **Figure 5.** Hydraulic fracture fluids typically consist of about 90% water, about 9% propping agent, and less than 1% functional additives.

reservoirs, water that has had guar gum added to increase its viscosity is a common fracture fluid.

The fracture fluid consists of more than 99% water and propping agent, with additives accounting for less than 1% of the fluid by volume. The breakdown of a typical fluid's composition is shown in Figure 5. Many of the additives are common products found in the home (Table 2).

Propping agent selection. During the fracture treatment, high-pressure pumps inject the fracture fluid into a wellbore at a high rate. This increases the pressure in the formation and cracks open the rock; continued pumping allows the cracks to grow in length, width, and height. After pumping ceases, the pressure in the fracture drops as the fluid dissipates through the natural fractures and sometimes into the rock matrix. To effectively stimulate the flow of gas from the well, the fractures need to be propped open to create conductive pathways from the reservoir into the fractures and down the fractures to the wellbore.

The most common propping agent is sand, which is available in many different grades. Premium sand is more rounded and more uniform in size, and has a higher compressive strength, than common sands that have natural fractures or flaws on the individual sand grains.

Sand can be coated with resin to increase the strength of the propping agent and to help minimize the flowback of the sand during gas production. Resin-coated sand is three to four times more expensive than uncoated sand, but in many cases that added cost could easily pay for itself through increased gas flowrates. The shale gas industry also uses synthetic propping agents, which consist of ceramic or bauxite particles that have been processed and sintered.

The selection of the propping agent is based on the maximum effective stress that will be applied to the propping agent during the life of the well. The maximum effective stress depends mostly on the depth of the formation that is being fracture-treated.

In general, if the maximum effective stress is less than 6,000 psi, sand is usually recommended as the propping agent. If the maximum effective stress is between 6,000 and 10,000 psi, either resin-coated sand or ceramic propping agents should be selected. If the maximum effective stress exceeds 12,000 psi, high-strength bauxite should be used. In cases where more liquids are going to be produced, the higher-strength, higher-permeability propping agents usually allow for the highest production rates.

These recommendations are rules of thumb; the engineer should also choose the propping agent on the basis of cost and well performance. It may be necessary to conduct trials in several wells to determine the optimum propping agent for a particular shale formation in a certain area.

Executing the fracture treatment in the field

A successful fracture treatment requires planning, coordination, and cooperation of many parties. Careful supervision of the treatment operation and implementation of quality-control measures can improve the success of the hydraulic fracturing.

Safety is always the primary concern in the field. Safety



begins with a thorough understanding by all parties of their duties in the field. A safety meeting should be held at the beginning of each stage of the fracture treatment to review the treatment procedure, establish a chain of command, ensure that everyone knows his/her job responsibilities for the day, and establish a plan for emergencies. At the safety meeting, the team should also discuss the well completion details and the maximum allowable injection rate and pressures, as well as the maximum pressures to be held as backup in the annulus.

Table 2. Most fracture fluid additives are common substances encountered in daily life.

Type of Additive	Function Performed	Typical Products	Common Use
Biocide	Kills bacteria	Glutaraldehyde	Dental disinfectant
Breaker	Reduces fluid viscosity	Ammonium persulfate	Hair bleach
Buffer	Controls the pH	Sodium bicarbonte	Heartburn-relief medicine
Clay stabilizer	Prevents clay swelling	Potassium chloride	Food additive
Gelling agent	Increases viscosity	Guar	Ice cream
Crosslinker	Increases viscosity	Borate salts	Laundry detergent
Friction reducer	Reduces friction	Polyacrylamide	Water and soil treatment
Iron controller	Keeps iron in solution	Citric acid	Food additive
Surfactant	Lowers surface tension	Isopropanol	Glass cleaner
Scale inhibitor	Prevents scaling	Ethylene glycol	Antifreeze

All casing, tubing, wellheads, valves, and weak links, such as liner tops, should be thoroughly tested prior to beginning the fracture treatment. Mechanical failures during a treatment can be costly and dangerous. Potential mechanical problems should be identified during testing and repaired before starting the fracture treatment.

Prior to pumping the treatment, the engineer in charge should conduct a detailed inventory of all the equipment and materials on location and compare this inventory to the design and the plan for the fracture treatment. After the treatment is concluded, the engineer should conduct another inventory of all the materials left on location. In most cases, the difference in the two inventories can be used to verify what was mixed and pumped into the wellbore and the formation.

Environmental issues. Many operators employ centralized facilities for drilling and fracturing operations. For example, the fracture fluid "pond" in Figure 6 serves as the source of the fracture fluid. The fluid is pumped from the pond to a nearby fracture treatment just before (or even during) the treatment. After treatment pumping is finished, the fluid that flows back from the formation is returned to the pond, treated, and reused. This helps to reduce the operation's environmental footprint and consumption of fresh water. It also cuts down the amount of truck traffic by limiting the number of trips needed to deliver water to the site and haul away wastewater for treatment.

Another way to reduce environmental footprint and minimize truck traffic is to drill multiple wells from a single pad. This approach has been used in parts of Appalachia and in the Rocky Mountains.

Microseismic measurements. Another issue surrounding shale gas production is whether fracture treatments cause earthquakes. The answer is yes and no:

• Yes. During a fracture treatment, the act of the rock breaking causes small microseismic events. The amount of energy released is equivalent to that of a gallon of milk falling off a counter and hitting the floor. These microseismic events cannot be felt at the surface. They can, however, be measured with extremely sensitive geophones, and the data used to map these events to locate where the hydraulic fracture is growing.

In the last few years, the shale gas industry has mapped microseismic data from thousands of wells and tens of thousands of fracture treatments. Warpinski and Fisher have analyzed and sorted the data for each formation by depth to locate the top and bottom of the fractures created during pumping and determine their proximity to the depth of the fresh water aquifers. Figure 7 presents these data for the Marcellus shale formation.

• No. Some very minor earthquakes have been associated with long-term water injection, mainly for water disposal. These earthquakes do not happen often, but when one does, simply stopping the injection prevents further earthquakes. However, these rare and small earthquakes have not been associated with hydraulic fracturing operations.

▲ **Figure 6.** A centralized fracture fluid pond can reduce an operation's environmental footprint.

Article continues on next page

Analyzing reservoir data

The most common methods used by reservoir engineers to determine reserves are volumetric calculations, material balance calculations, analysis of decline curves, and reservoir simulation and modeling.

Volumetric calculations. Volumetric methods work best in high-permeability gas reservoirs for which the drainage area and gas recovery efficiency are known with reasonable certainty. In such reservoirs, the volumetric method can provide relatively accurate estimates of the amount of original gas in place and gas reserves.

In shale gas reservoirs, the volumetric method might provide reasonable estimates of original gas in place. However, its estimates of gas reserves, which is the amount of OGIP that can be produced economically, are not as reliable because it is very difficult to estimate both the drainage area of a particular well and the recovery efficiency. Therefore, the volumetric method of estimating shale gas reserves should be used only prior to drilling the well. Once production data are available, those data should be evaluated to estimate reserves.

Material balance calculations. It is impossible to obtain accurate data to describe the drop in reservoir pressure as gas is produced. Thus, material balance methods should never be used in shale gas reservoirs.

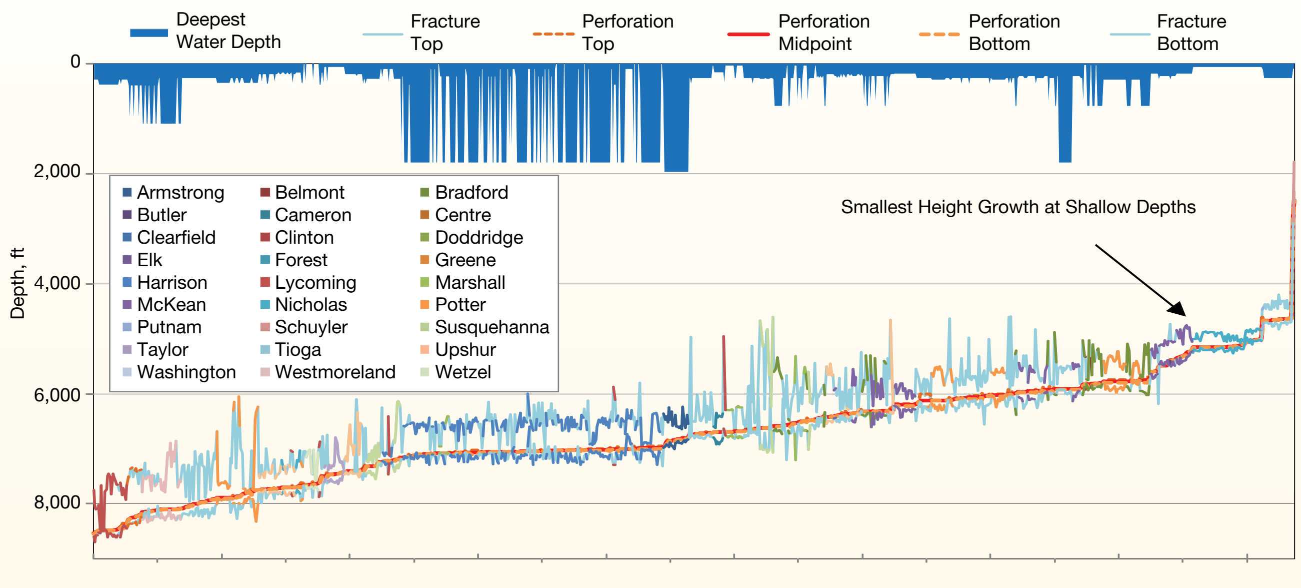
Decline curve analysis. The decline curve analysis method, which looks at the decrease in the gas production rate over time, works well for shale gas reservoirs, especially layered reservoirs that have been stimulated with a large hydraulic fracture or developed with a long horizontal wellbore. However, decline rates are high early in the life of a well (rates of 70% per year and more have been observed in the first year of production for a typical shale gas well containing a long horizontal wellbore). Thus, it is necessary to use a hyperbolic equation to curve-fit the data.

The decline rate becomes smaller over time, and after several years can be approximated by an exponential function. When the decline rate falls below about 6–8%, a constant decline rate of 6% to 8% can be assumed for the remaining life of the well.

Figure 8 is a typical exponential decline curve for a shale gas well. This well initially produces at a rate of 10 million cubic feet per day (MMcf/d), but this declines to 2.5 MMcf/d by the second year. After about three years, the flowrate levels off near 1 MMcf/d.

Figure 9 is a plot of the cumulative gas produced from the same well. Notice that the cumulative recovery after 10–12 yr is about 5,000 MMcf and that half of the ultimate recovery was produced during the first 4 yr. This makes the point that if a shale gas well does not pay out in the first few years, it may not be an economical investment.

Even when using the hyperbolic equation to analyze production from tight gas reservoirs, one must carefully analyze all of the data. For example, many wells begin producing at a high gas flowrate and high flowing tubing pressure (pressure in tubing that is open, for instance with open valves, rather than blocked in). If only the gas flowrate data are considered, the extrapolation into the future is unrealistically optimistic. However, during the first few weeks and months, both the gas flowrate and the flowing tubing

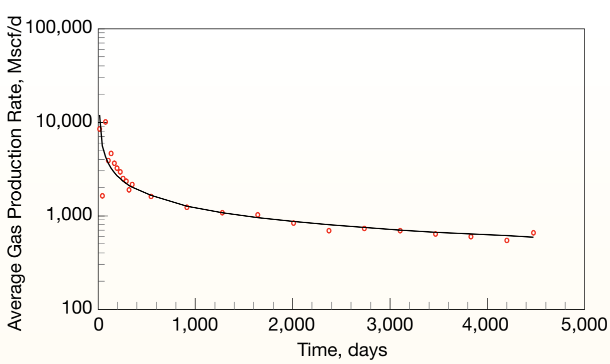


▲ **Figure 7.** Microseismic events resulting from hydraulic fracturing occur well below the water table. Source: *(1).*

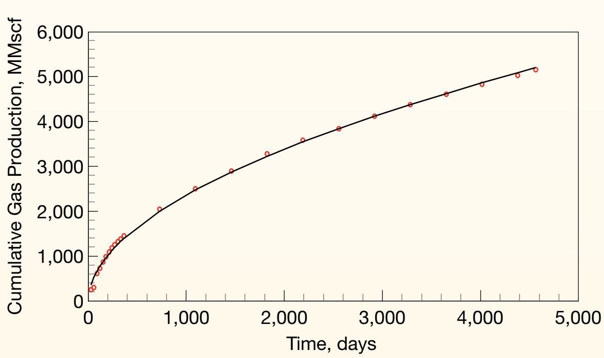
pressure decline. When the flowing tubing pressure reaches the pipeline pressure and stops declining, the gas flowrate decline rate increases. When both the gas flowrate and the flowing tubing pressure are declining, the engineer needs to divide the flowrate by the pressure drop and use the decline-curve model to match both the decline in flowrate and the decline in flowing tubing pressure.

Reservoir modeling method. The most accurate way to estimate gas reserves in tight gas reservoirs is to use a reservoir model, such as a semi-analytical model or a finite difference reservoir model that has been calibrated against historical production data. The model should be capable of simulating layered reservoirs, a finite-conductivity hydraulic fracture, and a variable flowing tubing pressure. In some cases, it might also be necessary to simulate non-Darcy flow, formation compaction, fracture closure, and/or fracture fluid clean-up effects.

The best use of shale gas reservoir simulation is to analyze data from a single well and run various what-if scenarios. Assuming it is possible to devise a reasonable reservoir description, the engineer can compute gas production vs. time for a variety of horizontal well locations, horizontal well lengths, fracture treatment spacings, and fracture treatment sizes. By comparing the results of the what-if analyses with actual field production data, one can start to understand the effects of different drilling and fracture treatment alternatives on gas production and economics.



▲ **Figure 8.** The rate of gas production decreases over time. The rate of decline is high early in the life of a well and eventually levels off.



▲ **Figure 9.** Approximately half of the gas ultimately recovered is produced in the first few years.

Economics of shale gas development

The economics of developing shale gas reservoirs are not unlike those of any other oil or gas reservoir. The decision to drill a well is based on producing enough oil and gas not only to recoup the well's costs in a reasonable time, but also to make a profit that is commensurate with the risk.

Most companies use cash-flow models to compute present-value profit and return on investment. While these precise calculations are required for banking and investment purposes, several rules of thumb can be used to make screening-level decisions:

• *payout* — if a well pays out in less than 5 yr, it will probably be economical to drill; a payout of 1–3 yr is an even stronger indicator of economic viability

• *discounted cash flow vs. costs* — if the discounted cash flow is three or more times the cost to drill the well, it will be economical.

Before discussing the economics of shale gas production, two terms need to be defined:

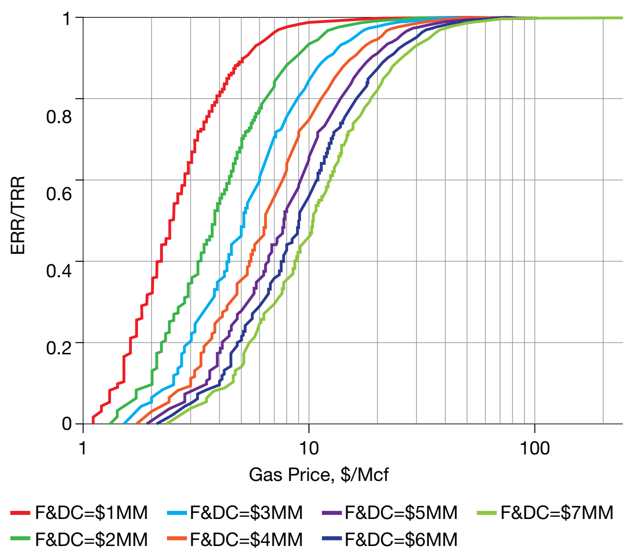
• *technically recoverable resourc*e (TRR) — the fraction of the OGIP that can be produced with available technology at a given point in time, without consideration of economics

• *economically recoverable resource* (ERR) — the gas that can be produced economically for specified values of finding and development costs, operating costs, and gas prices.

At Texas A&M Univ., we have developed a detailed model to calculate values of OGIP, TRR, and ERR for typical shale gas wells. We define an economical well as one that pays out in less than 5 yr and provides a 20% internal rate of return (IRR). To forecast cash flow, we analyzed production data from thousands of wells to determine the distribution of production for a variety of shale gas plays. (The term play refers to a geographical and geological area containing significant accumulations of gas.)

The Barnett Shale play in Texas covers around 3.2 million acres, and its OGIP is estimated to be 348 trillion cubic feet (Tcf). Over 13,000 wells have been drilled in the Barnett, more than 9,000 of which are horizontal. Over 8.9 Tcf of gas has already been produced. The estimated median TRR is approximately 49 Tcf. To fully develop this resource would require 29,000 wells.

Figure 10 is a plot of the ratio of ERR/TRR for the Barnett Shale for a variety of finding and development (F&D) costs ranging from $1 million to $7 million per well and gas prices ranging from $1/Mcf to $30/Mcf. This graph shows that at a typical F&D cost of $3 million per well



▲ **Figure 10.** The fraction of the technically recoverable resource that can be produced economically depends on the price of gas and the finding and development costs.

Table 3. The amount of gas that can be economically recovered from a well depends on the finding and development costs and the price of natural gas.

ERR/TRR	Barnett		Eagle Ford	
	F&D Cost, $MM	Gas Price, $/Mcf	F&D Cost, $MM	Gas Price, $/Mcf
25%	1	1.80	6	4.00
	2	2.30	7	4.10
	3	3.00	8	5.00
	4	4.00	9	5.20
	5	4.30	10	6.00
	6	5.20	11	6.30
50%	1	2.30	6	5.50
	2	3.80	7	6.00
	3	5.00	8	7.00
	4	6.10	9	7.20
	5	7.90	10	8.10
	6	9.00	11	9.00
75%	1	3.10	6	8.00
	2	5.10	7	9.00
	3	7.10	8	10.00
	4	9.50	9	10.30
	5	11.00	10	10.60
	6	13.00	11	11.00

and a gas price of $4/Mcf, about 35% of the TRR can be recovered economically.

Table 3 compares various combinations of F&D costs and gas prices required to economically produce 25%, 50%, and 75% of the TRR in the Barnett play and the dry-gas portion of the Eagle Ford play in South Texas.

For instance, the yellow-shaded cells show that if the F&D costs for a well in the Barnett are $3 million and the price of gas is $3/Mcf, 25% of the TRR could be produced economically, whereas it would not be economical to produce 75% of the TRR unless the price of gas hit $7.10/Mcf. Similarly, the orange-colored cells show that with F&D costs of $9 million per well in the dry-gas portion of the Eagle Ford, the price of gas would need to be $5.20/Mcf to economically produce 25% of the TRR, $7.20/Mcf for 50% of the TRR, and $10.30/Mcf for 75% of the TRR.

The green cells illustrate another way to look at the data. If the price of gas is assumed to average $6/Mcf over the long term, half the Eagle Ford's TRR can be produced economically if the F&D costs can be held below $7 million per well, while 75% of the Barnett's TRR can be economically recovered for about $2–3 million in F&D expenditures per well.

Closing thoughts

Shale gas can change the energy future of the U.S. and, eventually, the world. The enabling technologies — horizontal drilling and hydraulic fracturing — are not new. They are safe and proven technologies that have revolutionized the oil and gas industry. The economics of developing shale gas plays depend heavily on the finding and development costs and the price of natural gas. At gas prices of $4–10/Mcf, the industry should be able to economically produce 50% or more of the technically recoverable resource in the U.S. CEP

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