Tight Gas Sands

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Introduction

Tight gas is the term commonly used to refer to low-permeability reservoirs that produce mainly dry natural gas. Many of the low-permeability reservoirs developed in the past are sandstone, but significant quantities of gas also are produced from low-permeability carbonates, shales, and coal seams. In this paper, production of gas from tight sandstones is the predominant theme. However, much of the same technology applies to tight-carbonate and gas-shale reservoirs.

In general, a vertical well drilled and completed in a tight gas reservoir must be successfully stimulated to produce at commercial gas-flow rates and produce commercial gas volumes. Normally, a large hydraulic-fracture treatment is required to produce gas economically. In some naturally fractured tight gas reservoirs, horizontal wells can be drilled, but these wells also need to be stimulated.

To optimize development of a tight gas reservoir, a team of geoscientists and engineers must optimize the number and locations of wells to be 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 tight gas reservoirs than are required for higher-permeability conventional reservoirs. On an individual-well basis, a well in a tight gas reservoir will produce less gas over a longer period of time than one expects from a well completed in a higher-permeability conventional reservoir. As such, many more wells (closer well spacing) must be drilled in a tight gas reservoir to recover a large percentage of the original gas in place compared with a conventional reservoir.

Definition of Tight Gas Reservoir

In the 1970s, the U.S. 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. Actually, the definition of a tight gas reservoir is a function of many physical and economic factors. The physical factors are related by Darcy's law, as shown in the stabilized, radial-flow equation, Eq. 1, (Lee 1982).

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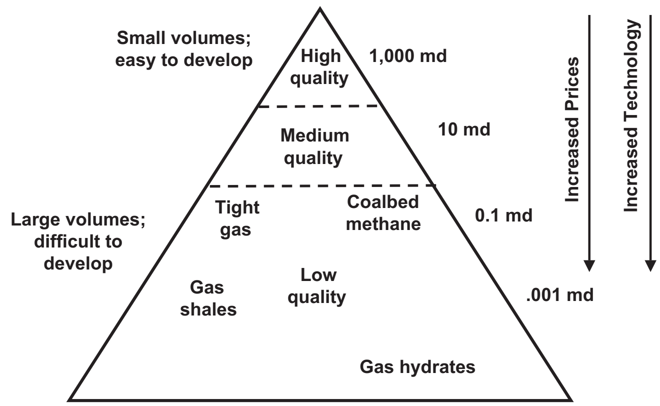

Fig. 1—Resource triangle for natural gas.

$$p_{wf}^2=\bar{p}^2-1{,}422\,\frac{\mu_{\bar{p}} z_{\bar{p}g} T q_g}{kh}\left[\ln\left(\frac{r_e}{r_w}\right)-0.75+(s+D|q_g|)\right]. \quad (1)$$

On the basis of Eq. 1, the flow rate, q, is a function of average reservoir pressure, $\bar{p}$; flowing pressure, p_{wf}; fluid properties, $\mu_{\bar{p}}$ and $z_{\bar{p}g}$; reservoir temperature, T; permeability, k; net pay thickness, h; drainage radius, r_e; wellbore radius, r_w; skin factor, s; and a non-Darcy flow constant, D. Thus, to choose a single value of permeability to define tight gas reservoirs is of limited significance. In deep, thick, high-pressure reservoirs, excellent completions can be achieved when the formation permeability to gas is in the microdarcy range (i.e., ~0.001 md). In shallow, thin, low-pressure reservoirs, permeabilities of several millidarcies might be required to produce the gas at economic flow rates, even after a successful fracture treatment.

The best definition of 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 use of a horizontal wellbore or multilateral wellbores."

So what is a typical tight gas reservoir? The answer is that there are no "typical" tight gas reservoirs. A tight gas reservoir can be deep or shallow, high-pressure or low-pressure, high-temperature or low-temperature, blanket or lenticular, homogeneous or naturally fractured, and can contain a single layer or multiple layers.

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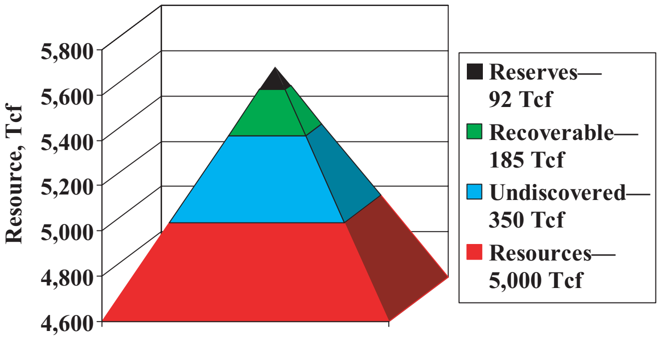

Fig. 2—Resource triangle for tight gas in the U.S.

The optimum drilling, completion, and stimulation methods for each well are functions of the reservoir characteristics and the economic situation. Some tight gas reservoirs are in south Texas, while others are in South America or the Middle East. The costs to drill, complete, and stimulate the wells, plus the gas price and the gas market, affect how tight gas reservoirs are developed.

Resource Triangle

The concept of the resource triangle was used by Masters (1979) to find a large gas field and build a company in the 1970s. The concept is that all natural resources are distributed log normally in nature. If you are prospecting for gold, silver, iron, zinc, oil, natural gas, or any resource, you will find that the best or highest-grade deposits are small in size and, once found, are easy to extract. The hard part is finding these pure veins of gold or high-permeability gas fields. Once you find the high-grade deposit, producing the resource is rather easy and straightforward. **Fig. 1** illustrates the principle of the resource triangle.

As you go deeper into the gas-resource triangle, the reservoirs are lower grade, which usually means the reservoir permeability is decreasing. These low-permeability reservoirs, however, are much larger in size than the higher-quality reservoirs. The scale on the right side of Fig. 1 illustrates typical values of formation permeability for tight gas sands. Other low-quality resources, such as coalbed methane, gas shales, and gas hydrates, would likely have different permeability scales.

The common theme is that low-quality deposits of natural gas require improved technology and adequate gas prices before they can be developed and produced economically. However, the size of the deposits can be very large compared with conventional or high-quality reservoirs. The concept of the resource triangle applies to every hydrocarbon-producing basin in the world. One should be able to estimate the volumes of oil and gas trapped in low-quality reservoirs in a specific basin by knowing the volumes of oil and gas that exist in the higher-quality reservoirs.

Tight Gas Sands in the U.S.

Estimates of gas production, reserves, and potential from the tight gas basins in the U.S. are compatible with the concept of the resource triangle. **Fig. 2** illustrates the tight gas resource-base estimates from the Gas Technology Inst. (GTI) (GTI E&P Services 2001). The gas produced through the year 2000 from tight gas reservoirs is estimated to be 58 Tcf. Proven reserves in tight gas reservoirs are 34 Tcf. Thus, the sum of produced gas plus proven reserves is 92 Tcf. Currently, the U.S. uses approximately 22 Tcf/yr of natural gas. It is estimated that 20% of the gas production in the U.S. currently comes from tight gas reservoirs.

GTI estimates the volume of technically recoverable gas from known U.S. tight gas accumulations at 185 Tcf. The term "technically recoverable" means that the gas is known to exist (the technology is available to drill, complete, and stimulate the wells and produce this gas), but the gas cannot be booked as reserves until the wells are drilled and the reservoirs are developed. The next category in Fig. 2 is called undiscovered, which represents the GTI estimate of gas that is likely to be discovered in known tight gas basins. Finally, the largest category is called resources. This value represents the gas in place in the U.S. tight gas basins. Substantial improvements in technology or changes in the gas market are required before the gas in the resources category can be produced economically.

Tight Gas Estimates Outside the U.S.

The resource-triangle concept should be valid for all natural resources in all basins in the world, so it is logical to believe that large volumes of gas in unconventional reservoirs will be found, developed, and produced in every basin that now produces significant volumes of gas from conventional reservoirs. There are various organizations that have analyzed parts of the unconventional-gas-resource base in specific regions of the world; however, no organization regularly publishes a comprehensive estimate of the volume of gas that might be found in unconventional reservoirs around the world.

Table 1 presents data from Kawata and Fujita (2001) who took the data from Rogner (1996). According to the estimates of Rogner, there are significant volumes of unconventional gas worldwide. The largest volumes of unconventional gas are known to exist in North America, which is also the region where there has been the most exploration, development, and production of unconventional gas. As such, there is more information available to evaluate the unconventional gas in North America.

TABLE 1—TABLE 1—DISTRIBUTION OF WORLDWIDE UNCONVENTIONAL-GAS RESOURCES (AFTER ROGNER 1996, TAKEN FROM KAWATA AND FUJITA 2001)

Region	Coalbed Methane (Tcf)	Shale Gas (Tcf)	Tight-Sand Gas (Tcf)	Total (Tcf)
North America	3,017	3,840	1,371	8,228
Latin America	39	2,116	1,293	3,448
Western Europe	157	509	353	1,019
Central and Eastern Europe	118	39	78	235
Former Soviet Union	3,957	627	901	5,485
Middle East and North Africa	0	2,547	823	3,370
Sub-Saharan Africa	39	274	784	1,097
Centrally planned Asia and China	1,215	3,526	353	5,094
Pacific (Organization for Economic Cooperation and Development)	470	2,312	705	3,487
Other Asia Pacific	0	313	549	862
South Asia	39	0	196	235
World	9,051	16,103	7,406	32,560

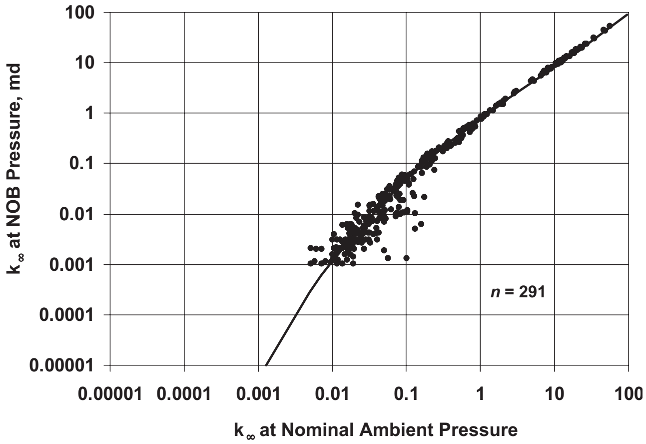

Fig. 3—Gas permeability at NOB pressure vs. gas permeability at ambient pressure for Howell No. 5 and SFE No. 2 Travis Peak cores.

It is likely that Rogner has underestimated the volumes of gas in unconventional reservoirs worldwide, because there are fewer data to evaluate outside of North America. When the resource-triangle concept is applied, the volume of gas in unconventional reservoirs around the world should be much larger than the volume of gas in conventional reservoirs. As more worldwide development occurs, more data will be available, and the estimates of worldwide unconventional-gas volumes will undoubtedly increase.

Without question, interest in tight gas reservoirs around the world increased substantially during the 1990s. In many countries, tight gas is defined by flow rate and not by permeability. Development activities and production of gas from tight reservoirs in Canada, Australia, Mexico, Venezuela, Argentina, Indonesia, China, Russia, Egypt, and Saudi Arabia have occurred during the past decade. Large hydraulic-fracture treatments are used more commonly around the world to stimulate gas flow from low-permeability reservoirs. Such activity will only increase during the coming decades.

Reservoir Considerations

Geology. The analysis of a tight gas reservoir should always begin with a thorough understanding of the geologic characteristics of the formation. The important geologic parameters for a trend or basin are the structural and tectonic regime, the regional thermal gradients, and the regional pressure gradients. Knowing the stratigraphy in a basin is very important and can affect the drilling, evaluation, completion, and stimulation activities. Important geologic parameters that should be studied for each stratigraphic unit are the depositional system, the genetic facies, textural maturity, mineralogy, diagenetic processes, cements, reservoir dimensions, and presence of natural fractures (Fisher and Brown 1972; Berg 1986).

Reservoir Continuity. One of the most difficult parameters to evaluate in tight gas reservoirs is the drainage-area size and shape. In tight reservoirs, months or years of production normally are required before the pressure transients are affected by reservoir boundaries or well-to-well interference. As such, the engineer often has to estimate the drainage-area size and shape for a typical well to estimate reserves. Knowledge is needed of the depositional system and the effects of diagenesis on the rock to estimate the drainage-area size and shape for a specific well. Oblong (or noncircular) drainage volumes are likely caused by depositional or fracture trends and the orientation of hydraulic fractures.

In blanket tight gas reservoirs, the average drainage area of a well largely depends on the number of wells drilled, the size of the fracture treatments pumped into the wells, and the time frame being considered. In lenticular or compartmentalized tight gas reservoirs, the average drainage area is likely a function of the average sand-lens size or compartment size and may not be a strong function of the size of the fracture treatment.

Regional Tectonics. Tectonic activity during deposition can affect reservoir continuity and morphology. In addition, regional tectonics affect the horizontal stresses in all rock layers. The horizontal stresses, in turn, affect faulting, rock strength, drilling parameters, hydraulic-fracture propagation, natural fracturing, and borehole stability. The main concerns for tight gas reservoirs are the effects of regional tectonics on hydraulic-fracture propagation and natural fracturing in the formation.

Reservoir Layers. Normally, a tight gas reservoir can be described as a layered system. In a clastic depositional system, the layers are composed of sandstone, siltstone, mudstone, and shale. To optimize the development of a tight gas reservoir, a team of geoscientists, petrophysicists, and engineers must fully characterize all the layers of rock above, within, and below the pay zones in the reservoir. Data concerning gross pay thickness, net pay thickness, permeability, porosity, water saturation, pressure, in-situ stress, and Young's modulus for all layers are required to use 3D reservoir and fracture-propagation models to evaluate the formation, design the fracture treatment, and forecast production rates and ultimate recovery. The raw data used to estimate values for these important parameters come from logs, cores, well tests, drilling records, and production from offset wells.

Log Data. Openhole logs provide the most economical and complete source of data for evaluating layered, low-porosity, tight gas reservoirs. The minimal logging suite for a tight gas reservoir comprises spontaneous potential, gamma ray, formation density, neutron, sonic, and dual (or array) induction logs. Other logs, such as wellbore-image logs or nuclear-magnetic-resonance logs, also may provide useful information in some reservoirs. All openhole logging data should be preprocessed before the data are used in any detailed computations. The steps required to preprocess the logs are as follows (Howard and Hunt 1986; Hunt et al. 1996 and 1997).

1. Digitize all log data.
2. Depth shift the data as required.
3. Perform all environmental corrections.
4. Normalize data so that all logs from different wells provide the same reading in the same zones, such as thick marine shales in which one expects the log readings to be consistent from well to well.

Core Data. Obtaining and analyzing cores are crucial to proper understanding of any layered complex reservoir system. To obtain data needed to understand the fluid-flow properties, mechanical properties, and depositional environment of a specific reservoir requires that cores be cut, handled correctly, and tested in the laboratory with modern and sophisticated laboratory methods. Of primary importance is the measuring of rock properties under restored reservoir conditions. The effect of net overburden (NOB) pressure must be reproduced in the laboratory to obtain the most accurate quantitative information from the cores (Jones and Owens 1980; Soeder and Randolph 1987).

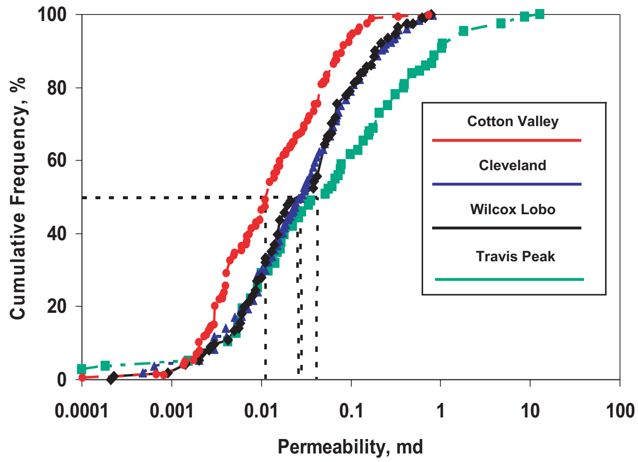

Fig. 4—Comparison of permeability distribution in four tight-sandstone gas formations in Texas using public data.

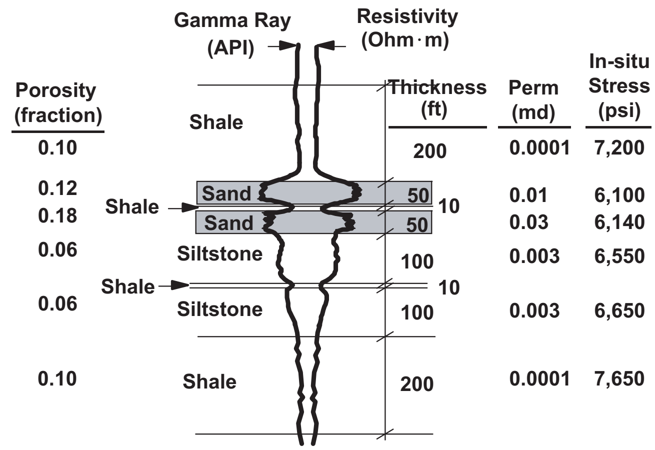

Fig. 5—Layer data required for evaluating the formation and designing the fracture treatment.

The measurements of porosity and permeability are a function of the net stress applied to the rock when the measurements are taken. For low-porosity rock, it is very important to take measurements at different values of net stress to understand fully how the reservoir will behave as the gas is produced and the reservoir pressure declines.

Fig. 3 illustrates the effect of NOB on the measurement of air permeability on Travis Peak cores from two wells in east Texas (CER Corp. and S.A. Holditch & Assocs. 1991). For high-permeability (10–100 md) core plugs, the permeability under the original overburden pressure is slightly less than the value of unstressed permeability for that same core plug. However, as the permeability of the core plugs decreases, the effect of NOB on the core plug increases substantially. For the core plugs that had values of unstressed permeability of approximately 0.01 md, the values of permeability under NOB were approximately an order of magnitude lower, or 0.001 md. The lower-permeability rocks are the most stress sensitive because the lower-permeability core samples have smaller pore-throat diameters than the higher-permeability rocks. To fully understand the properties of tight gas formations, special core analyses must be run on selected core plugs to measure values of gas permeability vs. water saturation, resistivity index, formation factor, capillary pressure, acoustic velocity, and the rock mechanical properties (Soeder and Randolph 1987).

Mechanical Properties. Most tight gas reservoirs are thick, layered systems that must be hydraulically fracture treated to produce at commercial gas-flow rates. To optimize the completion, it is necessary to understand the mechanical properties of all the layers above, within, and below the gas pay intervals. Basic rock properties, such as the in-situ stress field, Young's modulus, and Poisson's ratio, are needed to design a fracture treatment.

The most important mechanical property is in-situ stress, often called the minimum compressive stress or the fracture-closure pressure. When the pressure inside the fracture is greater than the in-situ stress, the fracture is open. When the pressure inside the fracture is less than the in-situ stress, the fracture is closed. Values of in-situ stress can be determined by use of logs, cores, or injection tests. To optimize the completion, it is very important to know the values of in-situ stress in every rock layer.

Permeability Distribution. Permeability in a gas formation within a basin is distributed log normally. To illustrate this concept, four data sets obtained from public records are presented for discussion. The data in **Fig. 4** are from the Travis Peak formation in east Texas, the Cotton Valley formation in east Texas, the Wilcox Lobo formation in south Texas, and the Cleveland formation in northwest Texas. These reservoirs are in different basins, but have very similar log-normal permeability distributions. The median permeability for the four formations ranges from 0.028 to 0.085 md, while the arithmetic mean values of permeability range from 0.179 to 7.378 md. The median permeability value is the best measure of central tendency. To forecast flow rates from an average well, one should use the median permeability value.

Vertical Profiles. To use either a multilayered reservoir model or a pseudo-3D (P3D) hydraulic-fracture propagation model, the data must be entered by reservoir layer. **Fig. 5** illustrates the profiles of important input data required by either the reservoir or the P3D model. For the situation in Fig. 5, the well is completed and the fracture treatment is initiated in the sandstone reservoir. Typically, the fracture grows up and down until a barrier is reached to prevent additional vertical fracture growth. Normally, siltstones or shaly sandstones have in-situ stresses similar to the sands and do not prevent vertical fracture growth. However, thick marine shales, which tend to have in-situ stresses that are higher than those of the sandstones, will be barriers to vertical fracture growth. Coal seams also may prevent fractures from growing vertically. Many coal seams are highly cleated, and when the fracture fluid enters the coal seam, it remains contained within the coal seam, which blunts vertical growth of the fracture.

Well Completion and Stimulation Considerations

Always of concern in the design of the completion is the number of producing zones that are separated in the reservoir by vertical-flow-barrier layers. If a single fracture treatment can be used to stimulate multiple layers, and no reservoir damage occurs by commingling the different zones, the well should be completed and stimulated with a single-stage treatment. Normally, in dry-gas reservoirs, no reservoir damage occurs by commingling different layers. In fact, it is likely that more gas will be recovered by producing all the layers in a commingled fashion because the abandonment pressure is lower at any given economic limit when the zones are commingled vs. producing the zones one at a time.

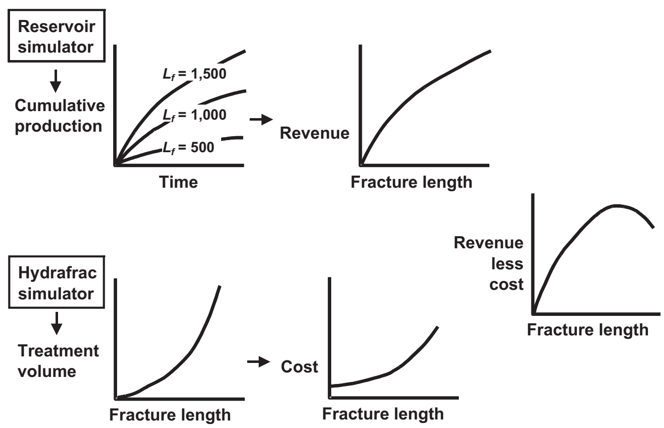

Fig. 6—Process to determine the economically optimum fracture length.

If two or more productive intervals are separated by a thick, clean shale (e.g., 50 ft or more) and this shale has enough in-situ stress contrast to be a barrier to vertical fracture growth, the design engineer might need to design the completion and stimulation treatments to consider that multiple hydraulic fractures will be created. In such cases, fracture-treatment-diverting techniques must be used to stimulate all producing intervals properly.

The goal of every design engineer is to design the optimum fracture treatment for each and every well. Holditch et al. (1978) discuss the optimization of both the propped fracture length and the drainage area (well spacing) for low-permeability gas reservoirs. **Fig. 6** illustrates the method used to optimize the size of a fracture treatment (Veach 1983; Gidley 1989).

Once the optimum fracture half-length has been determined, and the fracture fluid and fracture propping agent have been selected, the design engineer needs to use a P3D model to determine the details of the design, such as the optimum injection rate, optimum pad volume, need for fluid-loss additives, proper location for the perforations, and other details. After designing the optimum treatment, the design engineer must compute the costs of the proposed treatment to be certain the costs are not much different from the costs assumed during the treatment-optimization process. If the treatment costs are substantially different, the entire optimization loop (Fig. 6) should be retraced using the correct cost data.

Finally, the design engineer should go to the field to be sure the optimum treatment is pumped correctly as designed. Field quality control is extremely important. It does no good to collect the data and design the optimum treatment if it is not pumped correctly in the field.

Post-Fracture Reservoir-Evaluation Methods

Analyzing post-fracture production and pressure data requires a thorough understanding of the flow patterns in the reservoir (Lee and Holditch 1981). The technique applied to analyze the data must be compatible with the flow regime that is occurring when the data are collected. For a well containing a finite-conductivity hydraulic fracture, the flow regimes consist of bilinear flow, linear flow, transitional flow, and pseudoradial flow. These flow regimes can be defined in terms of dimensionless time. The times that encompass bilinear flow, linear flow, and transitional flow can be termed "transient flow."

TABLE 2—TIMES REQUIRED TO REACH LINEAR AND PSEUDORADIAL FLOW FOR A WELL CONTAINING A HYDRAULIC FRACTURE

Formation Permeability (md)	Fracture Half-Length (ft)	Start of Linear Flow (days)	End of Linear Flow (days)	Start of Pseudoradial Flow (days)
0.001	100	341	1,752	4,545
	500	8,523	43,788	113,636
	1,000	34,091	175,152	454,545
0.01	100	34	175	455
	500	852	4,379	11,364
	1,000	3,409	17,515	45,455
0.1	100	3	18	45
	500	85	438	1,136
	1,000	341	1,752	4,545
1	50	0.1	0.4	1.1
	100	0.3	1.8	4.5
	250	2.1	10.9	28.4

Assumptions
Porosity = 0.1 (fraction)
Viscosity = 0.02 cp
Compressibility = 0.002 Psi^{-1}

The flow regimes of a vertical well containing a finite-conductivity vertical fracture can be defined by use of the dimensionless time equation.

$$t_D = \frac{0.000264kt}{\phi \mu c_t L_f^2} \quad \text{(2)}$$

In a paper by Lee and Holditch (1981), it was shown that linear flow occurs between dimensionless times of 0.0225 and 0.1156. Pseudoradial flow of a well containing a finite-conductivity hydraulic fracture does not begin until a dimensionless time of 2 to 5, depending on the value of dimensionless fracture conductivity. Before reaching linear flow, the flow often is characterized as bilinear flow. Between the end of linear flow and the beginning of pseudoradial flow, the regime often is called transitional flow. The data in **Table 2** illustrate the actual times required to reach linear flow and pseudoradial flow for typical reservoir situations. Notice that for typical tight gas reservoirs, linear flow lasts for months or years. One should not use semisteady-state analysis methods on any data before reaching the start of pseudoradial flow, as shown in Table 2.

So how are early-time transient data from low-permeability gas reservoirs containing finite-conductivity fractures analyzed? The answer is that analytical or numerical solutions of Darcy's law must be used to analyze data properly in the transient-flow period. Many analytical transient-flow solutions for hydraulically fractured wells have been derived and published. In fact, there are too many to list in the references, but the first and most important analytical solutions were published by Russell and Truitt (1964), Gringarten et al. (1974), Cinco et al. (1978), and Agarwal et al. (1979).

In addition to the analytical solutions, Lee and Holditch (1981) showed that finite-difference modeling could be used to analyze data from tight gas reservoirs containing a finite-conductivity hydraulic fracture. Actually, the ideal solution is to first use the analytical models to analyze the data to determine first-order estimates of formation permeability, fracture half-length, and fracture conductivity and then use those values as input into a realistic finite-difference

TABLE 3—RESERVES-ESTIMATION METHODS FOR TIGHT GAS SANDS		
Method	Conventional Gas Reservoir	Tight Gas Sands
Volumetrics	Accurate in blanket reservoirs	Used only when no wells have been drilled
Material Balance	Accurate in depletion-drive reservoirs	Should never be used
Decline Curves	Exponential decline usually accurate	Must use hyperbolic decline
Reservoir Models	Used to simulate the field	Used to simulate individual wells

model. The finite-difference model can be used to determine the final estimates of the formation and fracture properties, taking into account effects such as non-Darcy flow, fracture closure, and formation compaction. The key is to use transient-flow models to analyze transient-flow data. If one tries to analyze data in linear flow with a pseudoradial-flow model (such as the Horner graph), one gets incorrect estimates of formation and fracture properties.

Estimating Reserves in Tight Gas Reservoirs

The most common methods used by reservoir engineers to determine reserves are volumetric, material balance, decline curves, and reservoir models. **Table 3** presents information concerning how these methods are used to evaluate high- and low-permeability gas reservoirs. Normally, volumetric methods do not work in tight gas sands because the proper drainage area to use in the computation is seldom known. Also, material balance seldom works in tight gas sands because it is almost impossible to shut in wells long enough to determine the current average reservoir pressure. As such, the best method to determine reserves in tight gas reservoirs is to analyze production data by use of either decline curves or reservoir simulation.

A typical decline curve for a tight gas well that was fracture treated in 1981, then recompleted and fracture treated again in 1992, is shown in **Fig. 7.** Notice that hydraulically fractured tight gas wells do not decline exponentially. In almost all cases, they will decline hyperbolically. Even when using the hyperbolic equation to analyze production from tight gas reservoirs, one must analyze all the data carefully. For example, many wells begin producing at high gas-flow rates along with high flowing tubing pressure. During the first few weeks and months, both the gas-flow rate and the flowing tubing pressure decline. If the analyst analyzes only the gas-flow-rate data, the extrapolation into the future is optimistic. Whenever the flowing tubing pressure reaches the pipeline pressure, and the flowing tubing pressure becomes steady, the decline rate of the gas-flow rate increases. Thus, when both the gas-flow rate and the flowing tubing pressure are declining, the analyst needs to compute values of $q/\Delta p$, or flow rate divided by pressure drop, and use the decline-curve model to match both the decline in flow rate and the decline in flowing tubing pressure.

The most accurate method of estimating gas reserves in tight gas reservoirs is to use a reservoir model, such as a semianalytical model or a numerical reservoir model, to history match gas-production and flowing-tubing-pressure data from the well. The model should be capable of simulating layered reservoirs, a finite-conductivity hydraulic fracture, and a changing flowing tubing pressure. In some cases, the analyst might also need to simulate non-Darcy flow, formation compaction, fracture closure, and/or fracture-fluid cleanup effects.

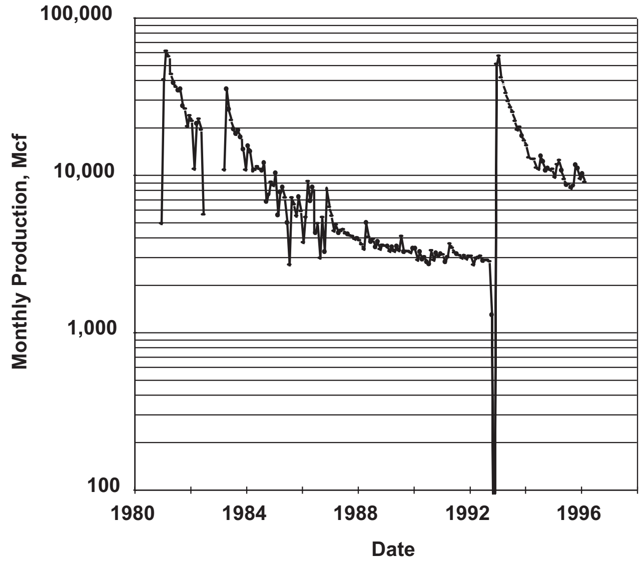

Fig. 7—Typical decline curve for a hydraulically fractured tight gas well.

Staged Field Experiments

The SPE eLibrary contains many papers that provide case histories of tight-gas-reservoir development. The GRI sponsored a multiyear research project to develop technology to design and evaluate hydraulic-fracture treatments in real time. The project produced data from four staged field experiments (SFEs) that can serve as templates for others who wish to collect and analyze data from tight gas sands and then use those data to design and evaluate the optimal completion and fracture treatment. In addition to four general papers covering the four SFEs (Holditch et al. 1988; Robinson et al. 1991; Robinson et al. 1992; Saunders et al. 1992), there are dozens of other papers in the SPE eLibrary. Complete reports are also available from the SPE store and from GTI, formerly known as the Gas Research Inst.

Summary

Tight gas sands have been developed in the U.S. for more than 40 years. During that time, substantial technology has been developed to improve success rate and economics. Much of that technology is now used worldwide to look for and develop tight gas sands. It is known that all natural resources, including natural gas, are distributed log normally in nature. This fact allows the industry to be certain that in virtually every basin that produces substantial volumes of natural gas from conventional reservoirs, large volumes of gas in unconventional reservoirs also will be present.

Tight-gas-reservoir characteristics vary considerably and are controlled by what is economic to develop in any given geologic region. Development costs, gas prices, and gas markets all must be considered when evaluating any tight gas play. Most of the known tight gas in the world is in North America because of the high activity level and the volume of data available for analysis. However, it is expected that activity levels in tight gas exploration will increase in the future in Latin America, Russia, the Middle East, Asia, and other major gas-producing areas.

To evaluate and develop a tight-gas-sand play properly, considerable data must be collected from cores, logs, drilling records, and well tests. Often, more data are needed to evaluate a tight gas sand than are needed to evaluate a conventional gas sand. In addition, the average tight-gas-sand well will produce less gas than a well in a conventional gas sand. As such, the geology and engineering team needs to develop log/core correlations that can be used to evaluate tight gas sands with a minimal logging suite.

By use of the correlations and openhole logs, the engineer must design the optimum well completion and stimulation treatment. Normally, a layered reservoir description is needed for the reservoir and P3D fracture models to determine where to perforate and what kind of fracture treatment is optimal. The engineer then needs to go to the field to be certain the optimal fracture treatment is pumped into the well and formation.

Finally, the only accurate way to forecast reserves is to analyze gas-production data and flowing tubing pressures. Volumetric methods will not provide accurate results in tight gas sands because the drainage area is not known. Material-balance methods do not work in tight gas sands because the wells cannot be shut in long enough to obtain an accurate estimate of average reservoir pressure. Thus, models must be used to analyze production data to obtain accurate reserves estimates. Also, models must be used to analyze gas-production and pressure data to determine the effective fracture length and conductivity.

There are large volumes of tight gas worldwide. The technology needed to evaluate, develop, and produce tight gas reservoirs has been under development for more than 40 years. Much of the technology can be found in the SPE eLibrary. In the next 40 years, there will be widespread development of tight gas reservoirs worldwide.

Nomenclature

c = compressibility, 1/psi
D = non-Darcy flow constant, D/Mscf
h = net pay, ft
k = permeability, md
L = fracture half-length, ft
p = pressure, psi
q = flow rate, Mcf/D
r = radius, ft
s = skin factor
t = time, hours or days
T = reservoir temperature, °R
z = gas-law deviation factor, dimensionless
Δ = difference
ϕ = porosity, fraction
μ = gas viscosity, cp
$\bar{\ }$ = overbar: average or mean

Subscripts

D = dimensionless
e = at the extremity of the reservoir
f = fracture
g = gas
$\bar{p}$ = evaluated at average pressure
t = total (for compressibility)
w = wellbore (for radius)
wf = bottomhole flowing (for pressure)

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