Tight Gas Reservoirs

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Society of Petroleum Engineers
222 Palisades Creek Drive
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Content Summary

Tight Gas Reservoirs

(Available in print or digital format. Parts 1, 2, and 3 are contained in this book. *Case Histories of Tight Gas Reservoir Development* is available only as a digital supplement. The content summary listed below is for reference purposes only.)

Part 1 – Unconventional Gas Resources

By Stephen A. Holditch
Contributions by Archna Agrawal, Sunil Ramaswamy, and Yao Tian

Chapter 1 Introduction to Unconventional Gas Reservoirs—Stephen A. Holditch
Chapter 2 Tight Gas Reservoirs—Stephen A. Holditch
Chapter 3 Coalbed Methane—Sunil Ramaswamy and Stephen A. Holditch
Chapter 4 Shale Gas—Archna Agrawal, Yao Tian, and Stephen A. Holditch

Part 2 – Tight Gas Sands Engineering

By Stephen A. Holditch, John Spivey, and John Yilin Wang

Chapter 5 Reservoir Characterization—Stephen A. Holditch
Chapter 6 Prestimulation Well Testing—John Spivey
Chapter 7 Post-Fracture Treatment Well Testing—John Spivey
Chapter 8 Rate Transient Analysis—John Spivey
Chapter 9 Well and Reservoir Numerical Modeling—John Yilin Wang and Stephen A. Holditch
Chapter 10 Drilling and Completion Design for Fracturing—Stephen A. Holditch
Chapter 11 Development Economics—John Yilin Wang and Stephen A. Holditch

Part 3 – Hydraulic Fracturing in Vertical Wells

By Stephen A. Holditch

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Chapter 13 Selection of Candidates
Chapter 14 Fracture Initiation, Geometry, and Propagation
Chapter 15 Data Acquisition and Core Measurements
Chapter 16 Fracturing Fluids and Additives: Properties and Selection
Chapter 17 Types of Fracture Propping Agents
Chapter 18 Hydraulic Fracture Treatment Design and Guidelines
Chapter 19 Planning and Executing a Hydraulic Fracture Treatment

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Tight Gas Reservoirs

Case Histories of Tight Gas Reservoir Development

Edited by Stephen A. Holditch and John Yilin Wang

(Available as an eBOOK SUPPLEMENTAL to *Tight Gas Reservoirs*. Download access will be granted at the time *Tight Gas Reservoirs* is purchased. The chapters listed below are available only in the supplemental digital download and not in this book. May or may not be available separately.)

23 articles from SPE literature covering different geological formations in the US and around the world.
New summaries are included that explain the significance of the research.

Chapter 1 The GRI Staged Field Experiment
Chapter 2 The Gas Research Institute's Second Staged Field Experiment: A Study of Hydraulic Fracturing
Chapter 3 Hydraulic Fracturing Research in East Texas: Third GRI Staged Field Experiment
Chapter 4 Hydraulic Fracturing Research in the Frontier Formation Through the Gas Research Institute's Fourth Staged Field Experiment
Chapter 5 Fracturing and Testing Case Study of Paludal, Tight, Lenticular Gas Sands
Chapter 6 Microseismic Monitoring of the B-Sand Hydraulic-Fracture Experiment at the DOE/GRI Multisite Project
Chapter 7 Successful Stimulation of Deep Wells Using High Proppant Concentrations
Chapter 8 A Case History of Massive Hydraulic Refracturing in the Tight Muddy "J" Formation
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Chapter 18 Stimulation Optimization in a Low-Permeability Upper Devonian Sandstone Reservoir: A Case History
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Foreword

The development of tight gas reservoirs over the previous half-century has profoundly affected and expanded the petroleum industry. Moreover, our improved understanding of tight gas reservoirs—from finding, characterizing, testing, modeling, and developing them to producing their resources economically—can be felt not only throughout our industry but also throughout our economy and, indeed, our daily routines.

Abundant, reliable, and inexpensive natural gas has truly transformed many aspects of our modern lifestyles. Within the last decade, for example, the world has made great strides in switching from coal-fired to gas-fired electricity generation, with a resulting reduction of US carbon-dioxide emissions of approximately 14% since 2005 (2017 BP Statistical Review of World Energy). Our expanded knowledge of natural-gas development and production has further advanced the goal of achieving energy independence, transforming the US from a gas importer into the third-largest liquid natural gas exporter in the world. It is hard to overstate the efficacy of our understanding and exploitation of tight gas reservoirs.

The four parts contained in this book methodically and comprehensively unfold the technical elements of developing tight gas reservoirs. They have been written with an industry-wide audience in mind; to help the student understand fundamental concepts; to provide comprehensive reference material for the experienced engineer; for the practitioner in the field looking for case studies and analogues; and for those readers curious about mathematical detail and theory, surely laying the foundation for many future academic investigations and doctoral theses.

This book is comprehensive enough to apply equally to those readers interested in tight oil reservoirs—common fundamentals, many similar concepts, just larger molecules.

The book's organization supports its methodological approach.

Part 1 introduces tight gas resources, including definitions and beginning concepts. Thorough analyses of tight gas resource types (shale, conventional tight gas, and coalbed methane) and their geographical distribution and reserves are provided. This part describes shale gas plays in North America in detail.

Part 2 begins where the study of all reservoirs begins, with detailed characterization. Chapters within this part discuss geological considerations over various scales, in addition to detailed concepts in well testing and modeling to determine necessary formation properties.

Part 3 details all aspects of designing, planning, modeling, and executing hydraulic fracturing treatments and provides details on fracture initiation, geometry, and propagation.

Case Histories of Tight Gas Reservoir Development (digital only) contains 23 chapters combining field and laboratory experiments in addition to revised and updated SPE manuscripts covering subjects from proppant transport to economic gas-reservoir development.

In summary, this book is the culmination of a lifetime of individual and collaborative work on all aspects of tight gas reservoirs. The material comes from a multitude of sources, including many Gas Research Institute field trials, worldwide consulting reports written over several decades, Schlumberger research and development activities, literally hundreds of graduate-student theses and dissertations and, of course, numerous SPE peer-reviewed articles and conference papers.

I am not capable of personally endorsing the entire content, but you can trust that many of our dedicated industry colleagues have reviewed the material and, in many cases, tested and verified it in tight gas reservoirs around the world. If you are looking for a reason to buy this book, perhaps the best is that it represents our industry's cumulative knowledge of tight gas reservoirs combined with decades of personal experiences in the implementation of the content.

Few people in our field have successfully combined deep intellect and old-fashioned know-how with leadership and vision. Perhaps even fewer have combined success and recognition with humility. Add a touch of stubbornness and a sense of humor, and you have our lead author. I cannot think of anyone with more credibility and respect than Dr. Stephen Holditch to assemble this compendium. When the leadership at SPE asked me to write the foreword for this book, I felt both honored and pleased to do so. I knew Steve for nearly 40 years, in many roles, from professor, friend, neighbor, and Schlumberger colleague to fellow golfer, hunter, and storyteller. Very simply, he was a great man and, like many, I miss him greatly. He has done more for our industry and our society and has impacted more lives, young and old, than anyone I can think of.

Now I am going to break a publishing rule or two and include in this foreword both an acknowledgment and a dedication, as the author sadly cannot. The final few drafts of this collective work, and the published version you now hold, could not have been completed, posthumously as it was, without the herculean efforts of the SPE publishing staff—Jane Eden, editorial services manager, and Rebekah Stacha, assistant director of technical publications, in particular—and also Dr. Ding Zhu, professor at Texas A&M University, who went to great effort to ensure the content was accurate and organized in the very readable manner Steve would have wanted and that you now see. Also, special thanks to David Grant, cover designer; Melinda Mahaffey Icden, editor; Lauren Miller, editor; Shashana Pearson-Hormillosa, editor; Dennis Scharnberg, technical editorial specialist; and Ingrid Scroggins, editor.

Steve Holditch was often a man of few words and rarely sentimental. If I knew him as well as I would like to think, though, I know he would surely want to dedicate this book—his magnum opus—to the loves of his life: his wife, Ann, and their daughters, Katie and Abbie. While reading, please keep in mind one of Steve's favorite maxims: "I retain the right to get smarter."

Jeff Spath
Professor and Holder of the Stephen A. Holditch '69 Department Head Chair
Harold Vance Department of Petroleum Engineering
Texas A&M University
March 27, 2020

Introduction

A Brief History of S. A. Holditch & Associates Inc.

In 1976, Stephen A. Holditch joined the faculty at Texas A&M University, followed by W. John Lee in 1977. That same year, S. A. Holditch & Associates Inc. was formed as a petroleum engineering consulting company. The consulting company initially focused on reservoir and production engineering aspects of tight gas reservoirs, to include well completions and hydraulic fracturing treatment design. One unique aspect of S. A. Holditch & Associates Inc. at the time was its approach, designing the optimal fracturing treatment in the office and then going to the field to make sure the optimal treatment was actually pumped in the ground.

S. A. Holditch & Associates Inc. continued to grow, and in 1983 it became the lead technical contractor for the Gas Research Institute (GRI) in its Tight Gas Sands (TGS) research focus area. The grand objective of the GRI tight gas research was to learn how to make measurements before, during, and after a fracturing treatment so the 3D size and shape of a hydraulic fracture could be calculated in real time. The GRI TGS research project lasted approximately 10 years, involved multiple contractors, and essentially achieved its goal by developing the first versions of the technology the industry commonly applies today.

The technology used today involves detailed data collection before and during a fracturing treatment, real-time analyses of the fracturing treatment data, 3D computations of fracture shape and dimensions, microseismic analyses to evaluate fracturing treatments, and complete data integration to better understand the fracturing treatment process. These technologies and systems are being applied worldwide by virtually all service companies to improve performance from unconventional reservoirs.

In addition to the TGS project, S. A. Holditch & Associates Inc. also became involved with the GRI Gas Shales project area and the GRI Coalbed Methane project area. The engineers and geoscientists at S. A. Holditch & Associates Inc. were fortunate to do a lot of cutting-edge work and were encouraged to publish the work in appropriate technical meetings. As a result, the family of professionals who worked at one time or another at S. A. Holditch & Associates Inc. has published several thousand technical papers pertaining to unconventional gas reservoirs. The group also has worked on several SPE textbook, monograph, handbook, and reprint series volumes. A bibliography of the body of work generated by employees of S. A. Holditch & Associates Inc. is found in *Case Histories of Tight Gas Reservoir Development*, available as a digital document from SPE.

By 1997, S. A. Holditch & Associates Inc. had opened five offices and had more than 50 employees. The business was more and more global, and it was decided that to continue to grow, the company needed to change its business model. At the same time, Schlumberger decided that it needed to focus on the reservoirs. Instead of deciding what to recommend to its clients on a well-by-well basis, Schlumberger needed to first understand what technology is required to maximize reservoir performance, then to determine how to drill, evaluate, complete, and stimulate individual wells to optimize the reservoir performance. As it turned out, the business goals of the two organizations were compatible, and Schlumberger purchased S. A. Holditch & Associates Inc.

Purpose of this Book

The purpose of this book is to document the technology allowing the industry to produce tight gas reservoirs. We highlight the contributions of the many employees at S. A. Holditch & Associates Inc. but do not limit our discussions because we want to include other important contributions to the technology. All of the information in this book can be found in the SPE literature, but it is convenient to pull it together in one place. We could not include everything, but we include enough references that the reader can find what is needed in either this book or the references.

Part 1 — Unconventional Gas Resources

Chapter 1

Introduction to Unconventional Gas Reservoirs

Stephen A. Holditch

Unconventional gas is the term commonly used to refer to low-permeability reservoirs that produce mainly dry natural gas (Holditch 2006). Many of the low-permeability reservoirs developed in the past were sandstone, but significant quantities of gas have also been produced from low-permeability carbonates, shales, and coal seams. The technology required to analyze and develop unconventional gas reservoirs has been developing for more than 50 years, since work began on hydraulic fracturing in the 1950s. In the 1960s, some unconventional gas was produced in places such as South Texas, the San Juan Basin, and the Devonian Shale in the Appalachian Basin.

In general, a vertical well drilled and completed in an unconventional gas reservoir must be successfully stimulated to produce at commercial gas flow rates and produce commercial gas volumes. A large hydraulic fracturing treatment normally is required to economically produce gas. In some unconventional gas reservoirs, horizontal and/or multilateral wells must be drilled, but many of these wells also need to be stimulated.

To optimize the development of an unconventional gas reservoir, a team of geoscientists and engineers must optimize the number of wells drilled, in addition to the drilling and completion procedures for each well. More data and more engineering manpower are often required to understand and develop unconventional gas reservoirs than are required for higher-permeability, conventional reservoirs. On an individual-well basis, a well in an unconventional gas reservoir will produce less gas over a longer period of time than that expected from a well completed in a higher-permeability, conventional reservoir. As such, many more wells must be drilled in unconventional gas reservoirs or smaller well spacing must be used to recover a large percentage of the original gas-in-place when compared with a conventional reservoir.

1.1 Definition of Unconventional Gas

In the 1970s, the US government decided that unconventional gas reservoirs were tight gas reservoirs, shale gas reservoirs, and coalbed methane (CBM) gas reservoirs. The Federal Energy Regulatory Commission (FERC) decided that a tight gas reservoir is one in which the expected value of permeability to gas flow would be less than 0.1 md. This was a political definition used to determine which wells would receive federal and/or state tax credits for producing gas from tight reservoirs. There was considerable discussion between producers and the FERC on the meaning of "expected value of permeability" and how to determine the correct method to average permeability. As will be explained in detail, the permeability in a natural gas reservoir is distributed log-normally. As such, the median or geometric mean value of permeability is the correct measure of the central tendency and should be used to determine the expected value of permeability.

Regardless of the political definition of unconventional or tight gas, the actual definition of an unconventional gas reservoir is a function of many physical and economic factors (Holditch 2006). The physical factors are related by Darcy's law, as shown by

$$q = \frac{kh\left(\overline{p} - p_{wf}\right)}{141.2\, B\mu \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} . \qquad (1.1)$$

Eq. 1.1 clearly shows that the flow rate q is a function of permeability k, net-pay thickness h, reservoir pressure $\overline{p}$, flowing pressure p_{wf}, fluid properties $B\mu$, drainage radius r_e, wellbore radius r_w, and skin factor s. Thus, to choose a single value of permeability to define tight gas is not wise. In deep, high-pressure, thick reservoirs, excellent completions can be achieved when the formation permeability to gas is in the microdarcy range (0.001 md). In shallow, low-pressure, thin reservoirs, permeabilities of several millidarcies might be required to produce the gas at economical flow rates, even after a successful fracturing treatment.

An unconventional gas reservoir is one in which "the reservoir 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, a horizontal wellbore, or by using multilateral wellbores" (Holditch 2006).

So, what is a typical unconventional gas reservoir? The answer is that there are no typical unconventional gas reservoirs. An unconventional gas reservoir can be a sandstone, shale, carbonate, or coal seam; deep or shallow; high or low pressure; high or low temperature; blanket or lenticular; homogeneous or naturally fractured; and single layered or multilayered.

The optimal drilling, completion, and stimulation methods for each well are a function of the reservoir characteristics and the economic situation. Some unconventional gas reservoirs are in South Texas, while others are in South America or the Middle East. The cost to drill, complete, and stimulate any particular well, in addition to the gas price and the gas market, affect how unconventional gas reservoirs are developed.

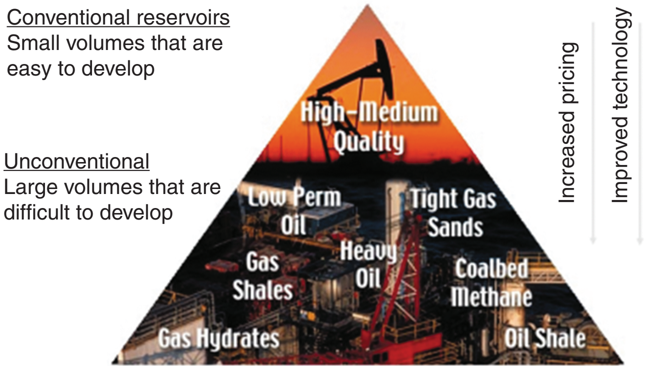


Fig. 1.1—The resource triangle for oil and gas.

1.2 The Resource Triangle

The resource-triangle concept was used by Masters (1979) and Gray (1977) to find a large gas field and build a company in the 1970s. In this concept, 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, easy to extract. The hard part is finding these pure veins of gold or high-permeability gas fields. After you find the high-grade deposit, producing the resource is rather easy and straightforward. **Fig. 1.1** illustrates the principle of the resource triangle.

As you go deeper into the gas resource triangle, the reservoirs are of 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 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 extremely large, when compared to conventional or high-quality reservoirs. The concept of the resource triangle applies to every hydrocarbon-producing basin in the world. You 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 and comparing the basin of interest to an analogous basin in North America, where substantial data sets are available concerning the size of the unconventional resource.

1.3 Geographical Information on Unconventional Gas

Unconventional resources, defined as those that have low permeability and require advanced drilling or stimulation technologies to be produced at commercial flow rates, have been an important component of the domestic natural gas supply base in the US for many years. From almost nonexistent production levels in the early 1970s, unconventional resources, particularly tight sands, today provide nearly 30% of the domestic gas supply in the US. Outside the US, with a few exceptions, unconventional gas resources have largely been overlooked and were understudied until approximately 2010. Unconventional gas resources represent a potential long-term global resource of natural gas and have not been appraised in any systematic way.

Unconventional gas resources—including tight sands, CBM, and gas shales—constitute some of the largest components of the remaining natural gas resources in the US. Research and development into the geologic controls of and production technologies for these resources during the past several decades have enabled operators in the US to begin to unlock the vast potential of these challenging resources. Because of their long-lived reserves and stabilizing influence on reserves portfolios, these resources are particularly attractive to natural gas producers.

1.4 Global Gas Resources

From a global perspective, tight gas sands resources are vast but largely undefined. Few systematic evaluations have been carried out on global emerging resources, and the magnitude and distribution of worldwide gas resources in gas shales, tight sands, and CBM formations have yet to be understood. Worldwide estimates, however, are enormous, with an early estimate of gas-in-place of approximately 32,000 Tcf by Rogner (1996). [See **Table 1.1,** Kawata and Fujita (2001).] The probability of this gas resource being in place is supported by information regarding and experience with similar resources in North America. The information in Table 1.1 was compiled in the 1980s and provides a conservative estimate of the volume of gas in unconventional reservoirs worldwide.

Dong et al. (2012), using methodology explained in Dong (2012) and following similar geographical divisions as Rogner (Kawata and Fujita 2001), produced the values shown in **Table 1.2.** Dong (2012) presented research of the published literature for every basin in North America and systematically recorded resource estimates for tight gas, coal seams, and gas shales. She then compared the many estimates and determined the most-likely value of the quantity of gas contained in each type of unconventional reservoir in each basin. Then, she developed correlations among unconventional-resource estimates and production from conventional reservoirs. These correlations were consistent with the theory of log-normal distribution, as explained by the resource triangle. The gas-in-place in coal seams was correlated with the volume of coal known to exist in each basin. The basins included in that research are shown in **Fig. 1.2.**

The OGIP values in Table 1.2 represent original gas-in-place (OGIP) estimates with a 50% probability. These numbers can be compared with the resource estimates in Table 1.1, compiled more than 20 years earlier and with much fewer data for evaluation. The best comparison is that for North America (NAM); Kawata and Fujita (2001) provided 8,228 Tcf as an estimate of the gas-in-place, while Dong et al. (2012) came up with 18,318 Tcf. Globally, Kawata and Fujita (2001) provided 32,559 Tcf of gas-in-place, while Dong et al. (2012) estimated that value to be 125,742 Tcf.

After determining the estimates of gas-in-place, Dong et al. (2012) used reservoir simulation to estimate the volume of gas that could be classified as a technically recoverable resource (TRR). TRR means (1) we know where the gas is located and (2) we have the technology to produce the gas. By "technology," we are referring to the fact that we know how to drill, complete, and stimulate tight gas sands, CBM reservoirs, and shale gas reservoirs.

Region	CBM OGIP (Tcf)	Shale OGIP (Tcf)	Tight Gas OGIP (Tcf)	Total (Tcf)
Australia and Asia (AAO)	1,724	6,151	1,802	9,677
North America (NAM)	3,017	3,840	1,371	8,228
Commonwealth of Independent States (CIS)	3,957	627	901	5,485
Latin America (LAM)	39	2,116	1,293	3,448
Middle East (MET)	0	2,547	823	3,370
Europe (EUP)	275	548	431	1,254
Africa (AFR)	39	274	784	1,097
World	9,051	16,103	7,405	**32,559**

* New emergence of UG plays around the world since 1997

* Uncertainty of Rogner's assessment was not quantified

Table 1.1—Distribution of worldwide unconventional gas (UG) resources (Kawata and Fujita 2001) using the work of Rogner (1996).

	OGIP (P50) (Tcf)				TRR (P50) (Tcf)			
Region	CBM	Tight Gas	Shale Gas	Total	CBM	Tight Gas	Shale Gas	Total
Australia and Asia (AAO)	1,348	6,253	2,690	10,291	483	3,783	676	4,942
North America (NAM)	1,629	10,784	5,905	18,318	584	6,525	1,505	8,614
Commonwealth of Independent States (CIS)	859	28,604	15,880	45,343	308	17,307	3,924	21,539
Latin America (LAM)	13	3,366	3,742	7,122	5	2,037	964	3,006
Middle East (MET)	9	15,447	15,416	30,872	3	9,346	4,000	13,349
Europe (EUP)	176	3,525	2,194	5,895	63	2,133	561	2,757
Africa (AFR)	18	4,000	3,882	7,901	7	2,420	1,007	3,434
World	4,052	71,981	49,709	**125,742**	1,453	43,551	12,637	**57,641**

Table 1.2—Distribution of worldwide unconventional gas resources and TRRs (Dong et al. 2012).

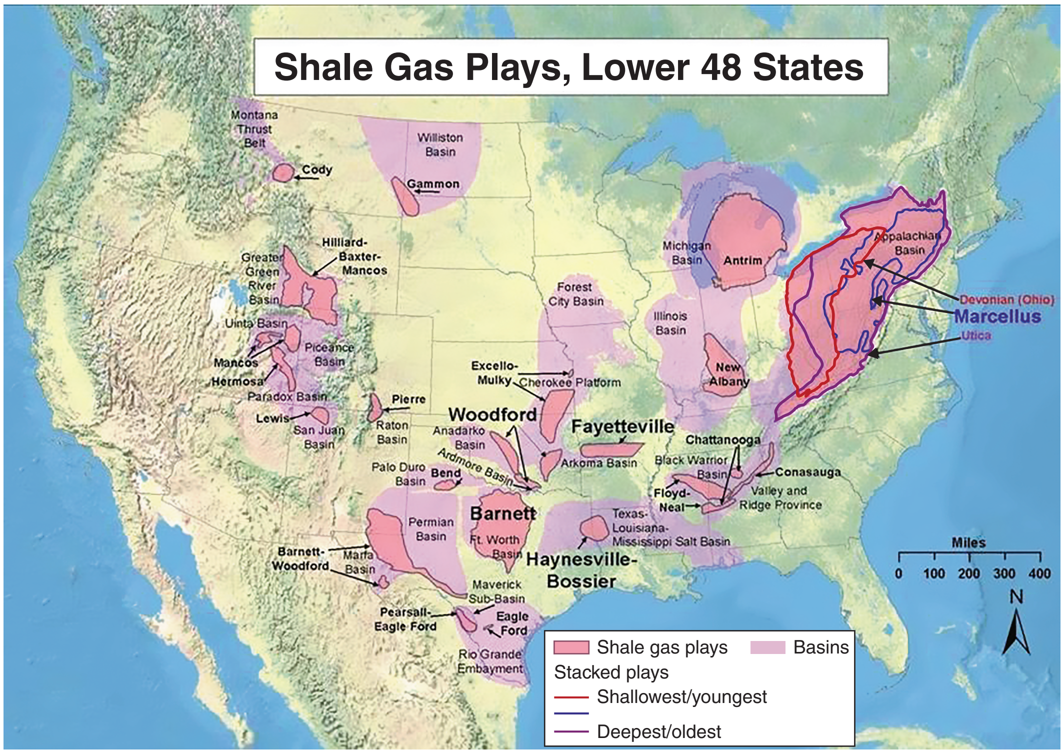
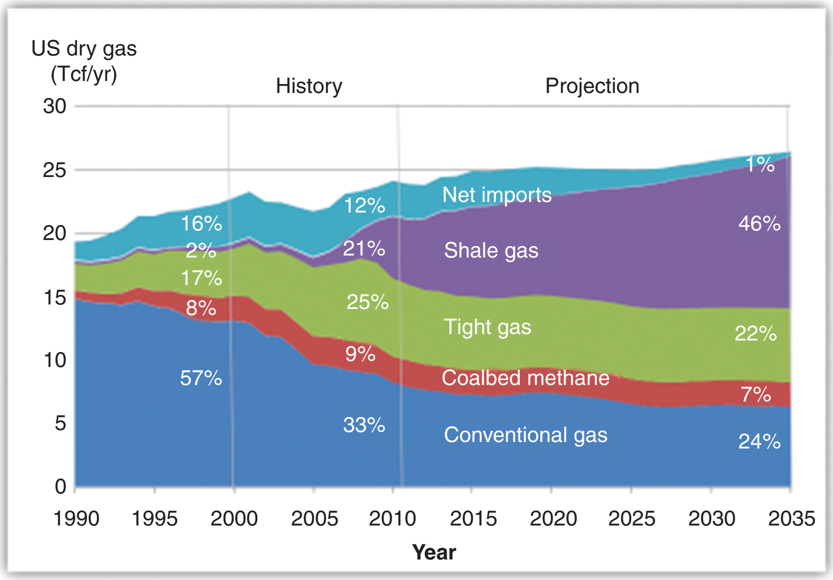

Shale Gas Plays, Lower 48 States
Montana Thrust Belt
Cody
Williston Basin
Gammon
Hilliard-Baxter-Mancos
Greater Green River Basin
Uinta Basin
Mancos
Hermosa
Piceance Basin
Paradox Basin
Lewis
San Juan Basin
Pierre
Raton Basin
Excello-Mulky
Cherokee Platform
Woodford
Anadarko Basin
Ardmore Basin
Palo Duro Basin
Bend
Forest City Basin
Fayetteville
Arkoma Basin
Barnett
Ft. Worth Basin
Permian Basin
Barnett-Woodford
Marfa Basin
Maverick Sub-Basin
Pearsall-Eagle Ford
Eagle Ford
Rio Grande Embayment
Haynesville-Bossier
Texas-Louisiana-Mississippi Salt Basin
Michigan Basin
Antrim
Illinois Basin
New Albany
Chattanooga
Black Warrior Basin
Conasauga
Floyd-Neal
Valley and Ridge Province
Appalachian Basin
Devonian (Ohio)
Marcellus
Utica
Miles
0 100 200 300 400
N
Shale gas plays
Basins
Stacked plays
Shallowest/youngest
Deepest/oldest

Fig. 1.2—Major unconventional gas basins (US Energy Information Administration 2010).

We are not claiming that all unconventional gas plays can be economically developed or that they will ever be developed. To develop a reservoir that is classified as TRR, one needs to have access to the land, drilling equipment, drilling personnel, completion equipment, completion personnel, hydraulic fracturing equipment, hydraulic fracturing personnel, a market for the natural gas, a gas pipeline, a reasonable gas price, the rule of law to make and enforce contracts, and proper infrastructure—such as roads and housing—just to name some of the considerations.

However, by classifying the gas as TRR—technically recoverable—it is acknowledged that the gas exists and can be drilled and produced if the mineral owners (usually the government) want it to be produced. We know how to do it. The question is: Does the ruling authority want us to produce the gas? Although not discussed in detail, Dong (2012) found that approximately 25 to 50% of the TRR is economically recoverable in basins that have the necessary infrastructure.

The volumes of gas produced from unconventional resources in the US are projected to only increase in importance over the next few decades. The US Energy Information Administration (EIA) forecast shown in **Fig. 1.3** illustrates that shale gas, tight gas, and CBM will comprise 75% of the gas produced in the US by the year 2035. In addition, notice that in 2010 the consumption of dry gas in the US was 23.8 Tcf/yr. For North America, the consumption was approximately 32 Tcf/yr.



2010 consumption: 23.8 Tcf/yr

UG: 13.2 Tcf/yr

Conventional gas: 7.8 Tcf

Net imports: 2.8 Tcf

Fig. 1.3—EIA forecast of US dry gas production (US Energy Information Administration 2011).

Using the TRR values in Table 1.2 and the demand for natural gas in North America, one can compute that there are several centuries of natural gas supply to meet demand, as shown in **Table 1.3.**

Area	OGIP (Tcf)	TRR (Tcf)	Usage (Tcf)	Supply (years)
North America	18,318	8,614	32	269
World	125,742	57,641	118	488

Table 1.3—Centuries of natural gas available.

1.5 Coal Seams

CBM is one of the best examples of how technology can have an impact on the understanding and eventual development of a natural gas resource. Gas has been known to exist in coal seams since the coal mining industry began, but significant gas production has been realized only since 1989 **(Fig. 1.4).**

CBM was drilled through and observed for many years yet never produced and sold as a resource. New technology and focused CBM research ultimately solved the resource-complexity riddle and unlocked its production potential. CBM now provides more than 1.6 Tcf of gas production per year in the US and is under development worldwide, including in Canada, Australia, India, and China.

The factors controlling CBM production behavior are similar to those for conventional gas resources in many respects; however, they differ considerably in important areas. One prominent difference is in the understanding of the resource, especially with regard to values of gas-in-place. Natural gas in coal seams adsorbs to the coal surface, allowing for significantly more gas to be stored than in conventional rocks in shallow, low-pressure formations. To release the adsorbed gas for production, we have to substantially reduce the pressure in the reservoir. Adsorbed gas volumes are not important for conventional gas resources but are very important for CBM reservoirs. Significant research was required in the 1990s to fully understand how to produce the adsorbed gas in coal seams and to develop the technology required to explore and produce CBM reservoirs.

A major difference between CBM reservoirs and sandstone gas reservoirs is that many of the coal seams are initially saturated with water. Thus, large volumes of water must be pumped out of the coal seams to reduce the pressure so that desorption will occur before seeing any significant gas production. The technology developed in the 1990s for understanding and dewatering coal seams paved the way for significant CBM development in several US geologic basins.

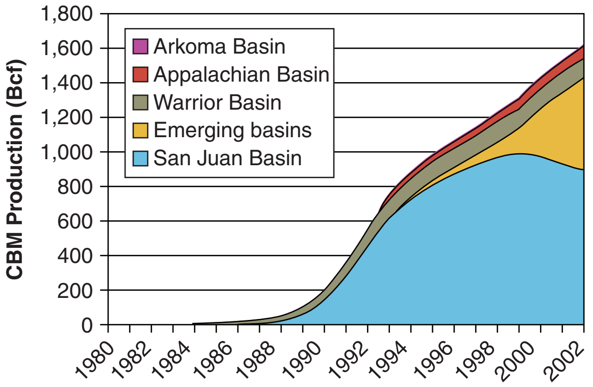


Fig. 1.4—Gas production from coal seams in the US.

1.6 Shale Gas

Shale formations act as both a source of gas and its reservoir. Natural gas is stored in shale in three forms: free gas in rock pores, free gas in natural fractures, and adsorbed gas on organic matter and mineral surfaces. These different storage mechanisms affect the speed and efficiency of gas production.

A global energy study (Rogner 1996) estimated that abundant shale gas resources are distributed mostly in North America, Latin America, and Asia Pacific (Table 1.1). Estimates suggest that the resource ranges from 1,483 to 1,859 Tcf in the US and 500 to 600 Tcf in Canada. In other regions of the world, this resource has been studied to a limited extent. Dong et al. (2012) raised those estimates, as shown in Table 1.2.

Commercial shale gas production first occurred in the US and was distributed in the Appalachian Basin, Michigan Basin, Illinois Basin, Fort Worth Basin, and San Juan Basin. Production increased rapidly in the 1990s and 2000s. In 2004, shale gas production in the US reached approximately 700 Bcf/yr, a huge increase from 350 Bcf/yr in 2000. Since the late 1990s, shale gas has been produced mainly in the Barnett, Haynesville, Fayetteville, Marcellus, and Eagle Ford; in a number of shales in the Rocky Mountain basins; and in western Canada. While technological innovations have increased per well with gas recovery efficiency, most of the increases in reserves have come from the increase in well density.

1.7 Nomenclature

$B\mu$ = fluid properties, cp

h = net-pay thickness, ft

k = permeability, md

$\overline{p}$ = reservoir pressure, psi

p_{wf} = flowing pressure, psi

q = flow rate, Mcf/D

r_e = drainage radius, ft

r_w = wellbore radius, ft

s = skin factor, dimensionless

1.8 References

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Chapter 2

Tight Gas Reservoirs

Stephen A. Holditch

Tight gas is the term commonly used to refer to low-permeability reservoirs that produce mainly dry natural gas. Tight gas reservoirs have one thing in common—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 fracturing treatment is required to produce gas economically. In some naturally fractured tight gas reservoirs, horizontal wells and/or multilateral wells can provide the stimulation required for commerciality.

To optimize the development of a tight gas reservoir, the 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 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 must be drilled (or smaller well spacing must be attained) in a tight gas reservoir to recover a large percentage of the original gas-in-place (OGIP) when compared to a conventional reservoir.

In the 1970s, the US government decided that a tight gas reservoir is one in which the expected value of permeability to gas flow would be less than 0.1 md. This was a political definition 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 factors, each relating to Darcy's law, as in Eq. 2.1:

$$q = \frac{kh\left(\bar{p} - p_{wf}\right)}{141.2\, B\mu \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]}. \qquad (2.1)$$

The main problem with tight gas reservoirs is that they do not produce at economic flow rates unless they are stimulated—normally by a large hydraulic fracturing treatment. Eq. 2.1 illustrates the main factors controlling flow rate and clearly shows that the flow rate q is a function of permeability k; net-pay thickness h; reservoir pressure $\bar{p}$; flowing pressure p_{wf}; fluid properties $B\mu$; drainage area r_e; wellbore radius r_w; and skin factor s. Thus, to choose a single value of permeability to define "tight gas" is not wise. In deep, high-pressure, thick reservoirs, excellent completions can be achieved when the formation permeability to gas is in the microdarcy range (0.001 md). In shallow, low-pressure, thin reservoirs, permeabilities of several millidarcies might be required to produce the gas at economic flow rates, even after a successful fracturing treatment.

The best way to define tight gas is that the reservoir cannot be produced at economic flow rates nor recover economic volumes of natural gas unless a special technique is used to stimulate production. Specifically, large hydraulic fracturing treatments, a horizontal wellbore, or multilateral wellbores must be used to stimulate flow rates and increase the recovery efficiency in the reservoir.

The optimal drilling, completion, and stimulation methods for each well are a function of the reservoir characteristics and the economic situation. Some tight gas reservoirs are in South Texas, while others are in the deserts of Egypt. The costs to drill, complete, and stimulate the wells, in addition to the gas price and the gas market, affect how tight gas reservoirs are developed. As with all engineering problems, the technology used is a function of the economic conditions surrounding the project.

2.1 Tight Gas in the US

Since the 1950s, the oil and gas industry has completed and fracture treated low-permeability wells in the US. However, it was the natural-gas price increase in the 1970s that spurred significant activity in low-permeability gas reservoirs. Since the 1970s, sustained increases in natural-gas prices—along with advances in evaluation, completion, and stimulation technology—have led to substantial development of low-quality gas reservoirs. **Fig. 2.1** shows the locations of the major tight gas basins in the US.

Fig. 2.2 illustrates the tight gas resource base estimates from the Gas Technology Institute (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 produced gas plus proven reserves adds up to 92 Tcf. GTI estimates the volume of technically recoverable gas from

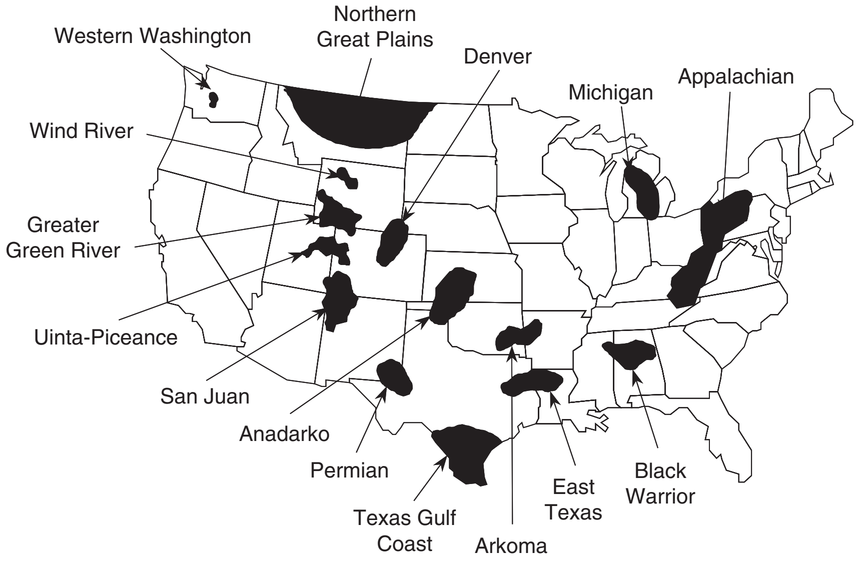

Fig. 2.1—Major US tight gas sands basins (after GTI E&P Services 2001).

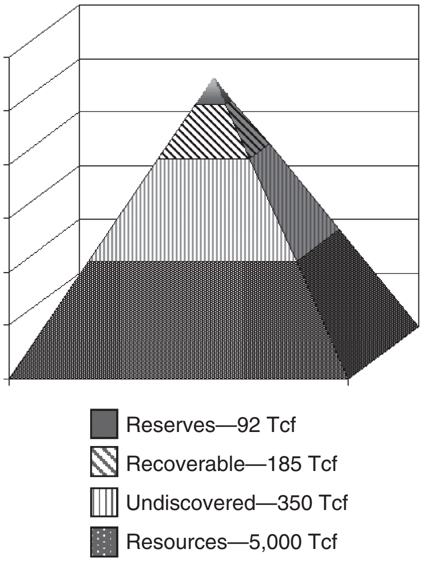

Fig. 2.2—Resource triangle for tight gas in the US (GTI E&P Services 2001).

known US tight gas accumulations at 185 Tcf. The term “technically recoverable” means the gas is known to exist and the technology is available to drill, complete, stimulate, and produce this gas; however, the gas cannot be booked as reserves until the wells are drilled and the reservoirs are developed. The next category in Fig. 2.2 is “undiscovered,” which represents the GTI estimate of gas that is likely to be discovered in known tight gas basins. Finally, the largest category is “resources,” which represents the gas-in-place in US 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.

2.2 Geologic Considerations

The analysis of any reservoir, including 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, genetic facies, textural maturity, mineralogy, diagenetic processes, cements, reservoir dimensions, and presence of natural fractures.

According to Fisher and McGowen (1967), a depositional system is a group of lithogenetic facies linked by depositional environment and associated processes. Each lithogenetic facies has certain attributes—including porosity, permeability, and special relations to other facies—that affect the migration and distribution of hydrocarbons. The nine principal clastic depositional systems reviewed by Fisher and Brown (1972) can be classified into three major groups, as illustrated in **Table 2.1.** Most tight gas sandstones that are being developed and produced in the US are located in barrier strand plains, deltaic systems, or fluvial systems (GTI E&P Services 2001). A few plays are found in shelf and fan-deltaic systems. Knowing the depositional system is important because it will affect the reservoir morphology and both the lateral and vertical continuity one expects in a reservoir. Details concerning clastic depositional systems can be found in Berg (1986) and Galloway and Hobday (1983). Refer also to Ch 5: Reservoir Characterization in Part 2 of this book.

Continental Environments
  Folian systems
  Lacustrine systems
  Fluvial systems
  Terrigenous fan (alluvial-fan and fan-deltaic systems)

Shoreline (Marginal Marine) Environments
  Deltaic systems
  Barrier-strand-plain systems
  Lagoon, bay, estuarine, and tidal-flat systems

Marine Environments
  Continental and intracratonic shelf systems
  Continental and intracratonic slope and basinal systems

Table 2.1—Classification of clastic depositional systems by environment.

2.2.1 Diagenesis. When most sands are deposited, the pores and pore throats are well-connected, resulting in high permeability. As explained by Berg (1986), sands are composed of mineral particles called grains, which usually consist of quartz, feldspars, and rock fragments. The finer particles between the grains are called matrix. The original porosity and permeability of a sandstone are