29th Annual GCSSEPM Foundation Bob F. Perkins Research Conference

December 6-8, 2009, Houston, Texas

Unconventional Energy Resources: Making the Unconventional Conventional

Program and Abstracts

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2009

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Houston Marriott Westchase
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Edited by

Tim Carr
Tony D'Agostino
William Ambrose
Jack Pashin
Norman C. Rosen

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Foreword

Driving down from Pittsburgh, Pennsylvania to Morgantown, West Virginia this week, on a clear November night, I could spot three drilling rigs working in a distance of thirty miles of highway. Given that hills of Appalachia tend to hide a lot of activity, this is astounding. I would hazard a guess that each of these rigs were targeting a resource (Marcellus Shale) that twenty-five years ago I had not given a second of thought about for one of my former employers, for when I was working on the eastern overthrust.

As stated by the late Nobel Laureate Richard Smalley, providing for our world's future energy and resource needs is one of the great challenges of this century. Increasing world populations (6.5 billion now, topping out at 9 billion in 2075) justly demand higher standards of living that require more access to energy. At the same time, increased energy demand will need to be accompanied by less pollution, especially emissions greenhouse gases. Sufficient energy is critical to our industrial, cultural, and health infrastructure, including agriculture, transportation, information technology, communication and many of the essentials that our civilization takes for granted.

The United States is a member of the Organization for Economic Co-operation and Development (OECD), which consists of the 30 wealthiest countries in the world (mean income over $33,000 per year in 2006). I usually refer to this as the rich boys club. The population of OECD countries number about one billion people and, on average, each year each individual consumes 217 million BTUs (10.8 tons of coal or 374 barrels of oil equivalent). On a per capita basis this is about 59 pounds of coal or about a barrel of oil per day. OECD countries represent only 17% of the world's population, but we consume 51% of the world's energy.

China, India, most of Latin America, and the rest of Asia have been industrializing with astonishing speed, yet their total energy consumption is only now beginning to increase rapidly. The per-capita annual energy consumption of the 83% of humanity with average incomes under $33,000 was 8.5 million BTUs per person, barely 4% of the average of the wealthiest countries - approximately 1.5 pints of oil or 2.25 pounds of coal equivalent per person per day. Numerous studies show that per capita annual consumption of about 100 million BTUs is necessary to provide barely minimal living standards in which infant mortality rates begin to decrease and approach 20 per thousand, and female life expectancies at birth begin to exceed 70 years. (For example, see Vaclav Smill, Energy at the Crossroads, 2003.) If the per capita energy consumption in the developing world were increased to only 50% of that presently consumed by the citizens of industrialized nations, and if everyone in the prosperous industrialized nations were to conserve down to that same level - that is, if everyone on earth used only 100 million BTUs of energy per year - energy production worldwide still would have to increase by more than 40% to 650+ quadrillion BTUs of energy(QBTU's) compared to present worldwide production of approximately 460 QBTUs. This is a tremendous challenge that can only be met by increasing our ability to tap resources that were previously unobtainable.

Energy, economy, and security are inextricably linked. Secure supplies of energy are a depleting resource subject to short-term disruption by political events. Energy resources must be constantly replenished through discovery of new resources and application of new technologies. However, attention should not be solely focused on conventional sources for oil and gas. Unconventional resources potentially could ensure supply of low-cost fuel well into the 21st century. An array of unconventional energy sources such as heavy oils, tar sands, oil shale and gas hydrates, as well as conventional, deeper ocean hydrocarbon resources, are being brought into play. Technological advances have opened up oil and natural gas resources that were previously unobtainable, including deepwater areas (depths >305 m) coal-bed methane, and gas in shale, that do not readily release their gas to wells. New unconventional resources such as oil shale and gas hydrates are poised to be delivered from theoretical resource to potential resource. The United States, as validated by history, has been the world leader in the development of technological solutions in many spheres of human endeavor and is leading the way again in developing and deploying the appropriate energy technologies to transform unconventional resources into conventional reserves.

In the opening keynote address, from Scott Tinker and Eric Potter of the Texas Bureau stress unconventional resources are positioned to provide a key source of energy as alternative, non-fossil energy sources are developed at commercial scale. They stress that unconventional reservoirs are predominantly in "primary" production phase. Similar to conventional oil and gas fields in the 1940's and 1950's, only a small percentage of the total global in-place unconventional resource base has been produced. There remains much to learn about unconventional resource systems and further research and development is required. This theme is reiterated in many of the papers that follow.

We have a series of five great papers on gas hydrates, which present formable technological challenges, but provide a potentially vast global resource to meet mid- and long-term energy demands. A series of field programs in the last decade, in conjunction with experimental studies and numerical simulation, show that it should be possible to extract the most favorable gas hydrates with existing technologies. There may be 20 quadrillion cubic meters of methane trapped within global deposits. Twenty five percent of this resource is enough natural gas to supply the United States at current levels for more than 7,500 years.

Seven papers address the hot gas shale plays in multiple basins across the United States and the world. New technologies are unlocking substantial amounts of shale gas. As a result according to the Potential Gas Committee (June 18, 2009), the nation's estimated gas reserves have surged an unprecedented 35 percent to 1,836 trillion cubic feet. Much of this increase is attributed to reevaluation of shale-gas plays in the Appalachian basin and in the Mid-Continent, Gulf Coast, and Rocky Mountain areas. Tapping this previously inaccessible resource is in full swing in the United States and is spreading to the rest of the world, raising hopes of a huge expansion in global reserves. One recent study cited in the New York Times (October 10, 2009, page A1) calculates that the recoverable shale gas outside of North America could turn out to be equivalent to 211 years worth of natural gas consumption in the United States at the present level of demand, and maybe as much as 690 years. In 2008, marketed US natural gas production was at its highest level in since 1974. In 2009, we may see an all time US record in marketed gas production. It is pretty clear that it is unconventional production that is providing the production boost.

In day two of the conference, we continue the theme of turning unconventional resources into conventional reserves and providing the energy for the future. Twelve papers cover coal-bed methane and tight gas and oil shale. Today tight gas makes up a significant portion of the nation's natural gas resource base, with the Energy Information Administration (EIA, January 2009) estimating that 309.58 Tcf of technically recoverable tight natural gas exists in the U.S. In 2008 according to the EIA, coal-bed methane production from basin across the US reached almost 2 TCF while were reserves approached 21 TCF. In oil shale there may be 1.2 trillion to 1.8 trillion barrels locked in the shale formations that underlie a vast region stretching from western Colorado to eastern Utah to southern Wyoming. Not all of that oil is recoverable, but by some of estimates, 800 billion barrels might be. That's more than three 'Saudi Arabias' worth of oil and enough to serve current U.S. demand for a century.

In summary, whether or not unconventional natural gas and oil production will grow in the future will depend on price, technology, and access. We have little control of two of these components, but conferences such as the **29th Annual Gulf Coast Section SEPM Foundation Bob F. Perkins Research Conference** ***Unconventional Resources: Making the Unconventional Conventional*** can help to advance the technology.

I am only the convener of the conference and would like to stress that this was a team effort. First I express my gratitude to the authors of the papers presented during the conference. They have produced an informative statement of the promise and technical challenges of transforming our unconventional resources into marketed energy. Their ideas will be of great value to their peers all around the industry.

My thanks to the Trustees of the Foundation and Norman Rosen, who advanced the idea of the symposium focused on unconventional resources. Norm provided continuous encouragement (gentle nagging), and the final editing of the papers that make up the volume. Bill Ambrose, Tony D'Agostino, Jack Pashin and Frank Walles were reviewers par excellence and worked to round up many of the papers. My thanks also are due to Paul Weimer of UC Boulder who worked to drum up additional papers. My considerable gratitude also goes to Gail Bergan of Bergan *et al.*, Inc., who had to wait and wait for us to provide the final manuscripts for the abstracts and published volume.

Tim Carr

Unconventional Energy Resources: Making the Unconventional Conventional

29th Annual Gulf Coast Section SEPM Foundation Bob F. Perkins Research Conference

Houston Marriott Westchase
Houston, Texas
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Program

Sunday, December 6

4:00–6:00 p.m. Registration and Poster Setup (Grand Pavilion)
6:00–8:00 p.m. Welcome Reception and Poster Preview (Grand Pavilion)

Monday, December 7

7:00 a.m.	**Continuous Registration (Grand Foyer)**
7:35 a.m.	**Presentation of Doris Curtis Award to John Armentrout**
7:45 a.m.	**Welcome remarks, Mike Styzen (Chair of the Board of Trustees, GCSSEPM Foundation) (Grand Pavilion)**
8:00 a.m.	**Introduction to the Conference, Tim Carr (Conference Convenor)**

Keynote Address

Session 1: Monday Morning—Gas Hydrates

8:40 a.m. **Introduction: William Ambrose**

10:00 a.m. Coffee break

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Cover Image

The cover image chosen for this year's conference is Figure 3 from Carroll: "Prospects and Progress in the Green River Formation Oil Shale, Western United States"

The Unconventional Bridge to an Alternate Energy Future

Tinker, Scott W.
Potter, Eric C.
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin

Abstract

The global energy marketplace is undergoing a predictable transition from coal in the 19th century, to oil in the 20th century, to natural gas and other non-fossil fuels in the 21st century. Oil as a percentage of total global energy "peaked" in 1979, and thus the 20th century will undoubtedly be remembered as the golden age of oil. The expansion of natural gas and other lower and non-carbon forms of energy in the 21st century has far-reaching implications and brings with it a number of favorable outcomes.

- Natural gas is abundant and is found in more regions than oil; this illustrates energy diversity and security of supply.
- With substantial growth expected in worldwide LNG in the coming decades, natural gas will have a global delivery infrastructure that will help stabilize energy prices, benefiting the macro-economies of most nations.
- A global natural gas infrastructure will help make the transition to alternatives smoother.
- Increased use of natural gas—to replace coal in power generation and oil in transportation—would help reduce atmospheric emissions.

A subtle but important corollary to the long-term trend toward natural gas shows an ever greater percentage of natural gas production coming from unconventional resources. One need only look to the United States, where coal-bed methane, shale gas and tight gas now represent over 50% of annual production (a benchmark achieved several years earlier than the Tinker forecast published in a 2004 *Oil and Gas Investor* article), and estimated unconventional natural gas resources have more than tripled the conventional gas resource base. As in the United States, a significant portion of the world's remaining natural gas resource is probably unconventional—tight gas, coal-bed gas, shale gas representing technologically proven unconventional resources; and methane hydrates, ultra deep (15,000 to 30,000 ft), and brine gas resources as possible future unconventional components. The bulk of the global unconventional natural gas has not yet been developed, and it represents an enormous untapped resource.

Gas Hydrate Petroleum Systems in Marine and Arctic Permafrost Environments

Collett, Timothy S.
U.S. Geological Survey
Denver Federal Center, MS-939
P.O. Box 25046
Denver, Colorado 80225

Abstract

A growing body of evidence indicates that a large volume of natural gas is stored in gas hydrates and that the production of natural gas from gas hydrates appears to be technically feasible. There are numerous research projects underway to investigate the geological origin of gas hydrate, their natural occurrence, the factors that affect their stability, and the possibility of using this vast resource in the world energy mix. Highly successful cooperative research projects, such as the various phases of the Mallik gas hydrate production project in northern Canada, have for the first time tested the technology needed to produce gas hydrates, and other highly successful gas hydrate research studies have been conducted in Japan, India, China, South Korea, northern Alaska, and the Gulf of Mexico. All of these projects have contributed greatly to an understanding of the energy resource potential of gas hydrates throughout the world.

Initial Results of Gulf of Mexico Gas Hydrate Joint Industry Project Leg II Logging-While-Drilling Operations

Boswell, Ray
U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, West Virginia 26507

Collett, Timothy S.
U.S. Geological Survey
Denver Federal Center MS-939 Box 25046
Denver, Colorado 80225

McConnell, Dan
AOA Geophysics
2500 Tanglewilde, Suite 120
Houston, Texas 77063

Frye, Matthew
U.S. Minerals Management Service
381 Elden Street
Herndon, Virginia 20170

Shedd, William
Godfriaux, Paul
Dufrene, Rebecca
U.S. Minerals Management Service
1201 Elmwood Park Blvd
New Orleans, Louisiana 70123

Mrozewski, Stefan
Guerin, Gilles
Cook, Ann
Lamont-Doherty Earth Observatory
Columbia University
61 Rt. 9 W
Palisades, New York 10964

Shelander, Dianna
Dai, Jianchun
Schlumberger
10001 Richmond Ave
Houston, Texas 77042

Jones, Emrys
Chevron Energy Technology Company
1500 Louisiana Street
Houston, Texas 77002

Abstract

The Gulf of Mexico gas hydrates Joint Industry Project (the JIP), a cooperative research program between the US Department of Energy and an international industrial consortium under the leadership of Chevron, conducted its "Leg II" logging-while-drilling operations in April and May of 2009. JIP Leg II was intended to expand the existing knowledge base on gas hydrates in the Gulf of Mexico to include the evaluation of gas hydrate occurrence in sand reservoirs. The selection of the locations for the JIP Leg II drilling was the result of a geological and geophysical prospecting approach that integrated direct geophysical evidence of gas hydrate-bearing strata with evidence of gas sourcing, gas migration, and occurrence of sand reservoirs within the gas hydrate stability zone. Logging-while-drilling operations for JIP Leg II included the drilling of seven wells at three sites. Despite drilling the deepest and most technically challenging well yet attempted in a marine gas hydrate program, the expedition was on time, under budget, and met all its scientific objectives. Minimal operational problems were encountered with the advanced LWD tool string, and the continual refinement of drilling parameters enabled the successful management of a range of shallow drilling issues, including borehole breakouts and shallow gas and water flows. Two wells drilled in Walker Ridge Block 313 (WR 313) confirmed the pre-drill predictions by discovering gas hydrates at high saturations in multiple sand horizons having reservoir thicknesses up to 50 ft. In addition, drilling in WR 313 discovered an unpredicted, thick, strata-bound interval of shallow fine-grained sediments having abundant gas-hydrate-filled fractures. Two of three wells drilled in Green Canyon Block 955 (GC 955) confirmed the pre-drill prediction of extensive sand occurrence having gas hydrate fill along the crest of a structure associated with positive indications of gas source and migration. Well GC955-H discovered ~100 ft of gas hydrate in sand at high saturations. Two wells drilled in Alaminos Canyon Block 21 (AC 21) confirmed the pre-drill prediction of poten-

tial extensive occurrence of gas hydrates in shallow sand reservoirs at low saturations.

Further data collection and analyses at AC 21 will be needed to better understand the nature of the pore filling material. The JIP plans to use the results of Leg II to plan Leg III drilling and coring operations anticipated to occur in 2010.

Production of Gas from Hydrate: How Much and How Soon?

Johnson, Arthur H.
Hydrate Energy International
612 Petit Berdot Drive
Kenner, Louisiana 70065

Abstract

Resource estimates for gas hydrate that have been reported during the past 30 years have pointed to a truly vast potential, but one that has persistently remained just over the horizon due to technical and economic hurdles. It is only in the last 10 years that commercial development of gas hydrate has been considered in the context of a petroleum system. The new focus is on components such as source, migration, traps, seals, and reservoir lithology. The petroleum system model, combined with recent drilling efforts, has led to revised resource estimates and viable production scenarios.

Most of the world's gas hydrate occurs in low concentrations in impermeable shales (comprising 3% to 5% of the sediment volume) or as isolated veins that cannot be commercially developed. In contrast, sands within the hydrate-stability zone typically have high hydrate saturations within the pore volume, exceeding 80% saturation in some locations. Although the gas hydrate reservoirs having commercial potential are only a small fraction of the global hydrate volume, they still have resource potential in the thousands of trillion cubic feet (Tcf). Although it is unrealistic to consider the global potential of gas hydrate to be in the hundreds of thousands of Tcf, there is a strong potential in the hundreds of Tcf or thousands of Tcf. The U.S. Minerals Management Service (MMS) estimates a total gas hydrate volume for the Gulf of Mexico of between 11,112 and 34,423 Tcf, and a mean estimate of 6,717 Tcf in place in sandstone reservoirs. A United States Geological Survey (USGS) assessment for the North Slope of Alaska reports a mean estimate of 85.4 Tcf technically recoverable from hydrate.

Gas has been produced from hydrate-bearing reservoirs on a very limited scale through short-term production tests in the Canadian Arctic and on the North Slope of Alaska. A long-term, industry-scale production test is planned for the North Slope in the summer of 2010 and the potential for hydrate development for local use following soon after. Production testing for hydrate in the Gulf of Mexico will follow within a few years. Japan is planning an offshore hydrate production test in 2011. Hydrate development programs are also in progress in India and South Korea.

Resource Potential of Deep-Water Hydrates Across the Gulf of Mexico: Part 1, Estimating Hydrate Concentration from Resistivity Logs and Seismic Velocities

Sava, Diana

Hardage, Bob

Bureau of Economic Geology

The University of Texas at Austin

diana.sava@beg.utexas.edu

Abstract

The Bureau of Economic Geology has evaluated hydrate concentrations across deep-water areas of Green Canyon, Gulf of Mexico, using well log data and four-component (4C) seismic data acquired by companies interested in deep oil and gas targets, not in near-seafloor hydrates. Even though these seismic and well log data are not acquired for purposes of studying near-seafloor geology, we have found these off-the-shelf industry data to be invaluable for evaluating hydrate systems positioned immediately below the seafloor. We summarize our data analyses and initial research findings in a two-paper sequence.

In this first paper, we describe how hydrate concentration can be estimated from resistivity logs and then from compressional (V_P) and shear (V_S) velocities as a joint-inversion approach for quantifying the amount of in-place hydrate. We found no industry well in the Green Canyon area where velocity-log data has been recorded across shallow near-seafloor strata where deep-water hydrates are found. Consequently, we have utilized interval V_P and V_S velocities obtained by processing deep-water 4C seismic data in our joint-inversion hydrate estimations.

The rock physics used to estimate deep-water hydrate concentrations from resistivity logs and from interval velocities is challenging because deep-water, near-seafloor sediments exist in a unique environment characterized by high porosities (greater than 50 percent) and low effective pressures (literally zero at the seafloor). Rock physics analyses are further complicated by the fact that resistivity and velocity responses to the hydrate fraction in seafloor sediments depend on whether the hydrate is layered (either horizontally or vertically) or dispersed, and if dispersed, whether the hydrate is part of the load-bearing matrix or is floating freely in pore spaces. Because the oil and gas industry is not yet focused on hydrate production, there is inadequate core information to define the specific hydrate-sediment morphology that should be used in a rock physics model that is applied to deep-water, near-seafloor environments in the Green Canyon area. In this first paper we illustrate how hydrate morphology affects the interpretation of resistivity and velocity responses of hydrate-bearing sediment. We have assumed a load-bearing morphology for our inversion work and await specific core information to know if this assumption needs to be modified in future work.

We have found that the Hashin-Shtrikman Lower Bound that can be used to describe the resistivity and elastic moduli of a mixture of arbitrary fractions of quartz, clay, hydrate, and brine is a critical concept for evaluating relationships between resistivity, velocity, and hydrate concentration in deep-water, near-seafloor environments. We discuss our rock physics modeling approach based on the application of Hashin-Shtrikman theory. In the second paper of this series, we describe how we combine the rock physics models that we have developed with velocity attributes determined from 4C seismic data to generate maps of hydrate concentration across our study area.

Resource Potential of Deep-Water Hydrates Across the Gulf of Mexico: Part 2, Evaluating Hydrate Systems with 4C OBC Seismic Data

Hardage, Bob
Sava, Diana
Murray, Paul
DeAngelo, Mike
Bureau of Economic Geology
The University of Texas at Austin
bob.hardage@beg.utexas.edu

Abstract

We have evaluated hydrate concentrations across deep-water areas of Green Canyon, Gulf of Mexico, using well log data and four-component (4C) seismic data acquired by companies interested in deep oil and gas targets, not in near-seafloor hydrates. Even though the data are not acquired for purposes of studying near-seafloor geology, we have found these off-the-shelf industry data to be invaluable for evaluating hydrate systems positioned close to the sea floor. We summarize our data analyses and initial research findings in this publication as a two-paper sequence.

In this second paper of our two-part series, we describe how two images of deep-water hydrate systems can be made from four-component ocean-bottom-cable (4C OBC) seismic data: a compressional (P-P) image and a converted-shear (P-SV) image. We further illustrate how we implement a raytracing procedure to determine accurate values of P-wave velocity (V_P) and SV-mode velocity (V_S) across thin subsea-floor layers. These interval velocities are used with the rock physics theory described in our first paper of this two-paper sequence to (1) estimate hydrate concentration at calibration wells where there are resistivity logs to use for an independent calculation of the hydrate fraction, and (2) expand the hydrate estimation along 4C seismic profiles that extend long distances away from calibration wells.

We present maps of hydrate concentration estimated by our data analyses and physical assumptions. We found hydrate concentration to not exceed 40 percent of the available pore space across our Green Canyon study area and to usually be in the range of 10 to 20 percent of the available pore volume.

How Technology Transfer Will Expand the Development of Unconventional Gas, Worldwide

Holditch, Stephen A.
Harold Vance Department of Petroleum Engineering
Texas A&M University
3116 TAMU
College Station, Texas 77843-3116

Ayers, Walter B.
Harold Vance Department of Petroleum Engineering
Texas A&M University
3116 TAMU
College Station, Texas 77843-3116

Abstract

For more than 50 years, the U.S. natural gas industry has been developing unconventional gas reservoirs. Production of natural gas from eastern Devonian Shales and tight gas sands in Texas and in the Rocky Mountain and Midcontinent regions has been the proving ground for many innovations in well drilling, completion, and stimulation. Over the past two decades, successful gas production from coal seams and from shales, such as the Barnett Shale, has led to new drilling and completion technologies. In 2007, unconventional gas production was 9.15 Tcf, accounting for 47% of the U.S. dry gas production, and eight of the top ten U.S. gas plays were producing from unconventional reservoirs. Unconventional gas reservoirs, led by shale, are expected to provide the majority of the U.S. gas supply growth in coming decades. Clearly, many basins worldwide contain large volumes of unconventional gas resources that have not been assessed. As conventional oil and gas reservoirs are depleted in those basins, inevitably, unconventional gas reservoirs will be developed. The key to successful development will be the proper application of existing technologies and the continued development of new technologies.

Over the past 5 years, a team of engineers and geoscientists in the Crisman Institute at Texas A&M University have worked to capture the critical geologic and engineering properties of unconventional gas reservoir in 25 North American basins. The primary objectives of this research are to (1) understand the gas resource distributions and the best technologies for unconventional gas recovery and economics, and (2) assess the volumes of unconventional gas in basins, worldwide, beginning with North America, using the concept that resources are log-normally distributed (resource triangle). Our evaluations of North American basins indicate that the Technically Recoverable Resource of unconventional gas in any basin will be approximately 5-10 times greater than the ultimate recovery (cumulative production plus proved reserves) from all conventional oil and gas reservoirs in the same basin.

Our research shows that historic unconventional gas drilling and production have been impacted strongly by technology and gas prices. The oil and gas industry should continue developing new technology to access unconventional gas reservoirs in diverse settings. The Research Partnership to Secure Energy for America (RPSEA) is supporting the development of new technology to optimize recovery of unconventional gas resources in the U.S. In coming decades, this technology that is being developed in the U.S. will be deployed worldwide to increase natural gas production from unconventional reservoirs and to contribute needed energy supplies.

Addressing Conventional Parameters in Unconventional Shale-Gas Systems: Depositional Environment, Petrography, Geochemistry, and Petrophysics of the Haynesville Shale

Hammes, Ursula

Eastwood, Ray

Bureau of Economic Geology

Jackson School of Geosciences

The University of Texas at Austin

Austin, Texas 78713

Ursula.Hammes@beg.utexas.edu

Rowe, Harry D.

Department of Earth and Environmental Sciences

Box 19049

University of Texas at Arlington

Arlington, Texas 76019

Reed, Robert M.

Bureau of Economic Geology

Jackson School of Geosciences

The University of Texas at Austin

Austin, Texas 78713

Abstract

The Upper Kimmeridgian to Lower Tithonian Haynesville Shale of East Texas was deposited in a basin rimmed by carbonate platforms to the west and north during a second-order transgression spanning 154–150 Ma. The Haynesville shale gas play is an important resource target in Louisiana and East Texas. Wells are characterized by high initial production and steep decline rates. Potential estimated ultimate recovery (EUR) per well is in the range of 4–7 Bcf, and play-reserves of more than 100 Tcf. However, depositional environmental, mineralogy, lithology, textures, geochemistry, porosity, permeability, and wireline-log characteristics are all poorly documented or understood. This paper addresses previously undocumented parameters related to depositional setting, facies, diagenesis, pore space, petrophysics, and significant geochemical markers of the Haynesville Shale.

The Haynesville Shale was deposited in a basinal setting surrounded by carbonate shelf of the Haynesville/Cotton Valley Lime. Cotton Valley pinnacle reefs grew within the shale-rich basin. Deposition was during a rapid second-order transgression that resulted in backstepping of carbonates and smothering of carbonate production by the Haynesville fine-grained sediments. Carbonates were shed into the basin via gravity flows. The basin periodically exhibited a restricted environment of reducing anoxic conditions, as indicated by Molybdenum (Mo) and Fe/S concentrations. Relatively high TOC values (1–8%) are typical of these mudrocks that ranged from calcareous, laminated and/or bioturbated mudstones to unlaminated siliceous mudstones. Bioturbation may be indicative for smaller-scale sea-level fluctuations and/or anoxic/oxic cycles. Pores are limited and small in size, occurring as micropores and nannopores in both intraparticle and interparticle forms. Nanopores are common and well-developed in some organic matter. Kerogen is seen to affect responses of all logs used for petrophysical characterization of porosity and lithology. Therefore, corrections must be applied when calculating porosity and clay volume.

Ancestral Basin Architecture: A Possible Key to the Jurassic Haynesville Trend

Martin, Bruce J.
25630 Zion Lutheran Cemetery Rd.
Tomball, Texas 77375

Ewing, Thomas E.
Yegua Energy Associates LLC
19240 Redland Rd Ste 200
San Antonio, Texas 78259

Abstract

Ancestral Gulf Coast Basin architecture controls much of the Jurassic Haynesville shale mudstone trend. Basement blocks developed during Early and Middle Jurassic rifting and overlain by a variable thickness of Louann Salt ultimately formed the foundation of large Haynesville (Gilmer) carbonate platforms that provide boundaries to the Haynesville organic shale trend. Salt movement influenced by basement features created local fairways of salt deflation, which received thicker Haynesville organic shale sequence and experienced less subsequent disruption. Available data sets indicate that salt movement in the Sabine uplift area terminated during the Late Jurassic. Therefore, post-Jurassic faulting was minimized, preventing hydrocarbon loss from the Haynesville organic shale reservoirs.

It is further proposed that the complex interaction of basement and salt structuring control the unique characteristics of the Haynesville shale mudstone reservoirs. Upwelling and/or other enrichment processes were controlled by paleo-structuring. The most favorable sites are the eastern and southern flanks of the ancestral Sabine platform. An understanding of salt movement via analysis of gravity-magnetic data closely tied to seismic and well control provides an inexpensive, yet effective means of mapping large areas. Detailed high-resolution gravity and magnetic mapping may provide even further insights for exploitation at lower cost than expensive 3D seismic.

Presently, the extent of the Haynesville trend along the Sabine platform is not fully defined, due in part to a lack of deep well control. This is particularly true along the Texas side, where thick Haynesville/Bossier flanking wedges are unexploited, and are beyond present economic limits. Should these wedges provide favorable facies when tested, exploration could shift to a deeper southern extension of the trend.

In certain areas, younger Jurassic faulting is coincident with older reactivated basement trends, providing avenues for hydrothermal fluid pathways. These pathways may have allowed hydrothermal fluid migration into the overlying Haynesville shale mudstone reservoirs and certain Haynesville carbonate reservoirs potentially enhancing these reservoirs. Mineral assemblages associated with thermo-chemical sulfate reduction have been found near these faulted areas, indicating the migration of hydrothermal fluid. In at least one case, dissolution by such fluid migration has resulted in a substantial void or karst style secondary porosity in the Haynesville carbonate section. The extent of this activity is unknown due to the limited deep well control. However, it may be extensive due to the high geothermal signature prevalent in the southern and eastern parts of the Haynesville play area.

Future exploration of the Haynesville trend will depend upon duplicating key factors found in the Sabine area. Workflows utilizing reconnaissance tools may help companies in updating their basin architecture models. Applying unconventional exploration workflows in combination with the understanding of hydrothermal flows to the Jurassic Salt Basins may help unlock other potential areas, allowing for revitalization of a mature region.

Arkoma Basin Shale Gas and Coal-Bed Gas Resources

Milici, Robert C.
Houseknecht, David W.
Garrity, Christopher P.
Fulk, Bryant
U.S. Geological Survey
956 National Center
Reston, Virginia 20192

Abstract

Shale gas is produced from the Woodford, Caney, and Fayetteville shales (Devonian and/or Mississippian), and coal-bed gas is produced from the Hartshorne and McAlester coal beds in the Arkoma basin of Oklahoma and Arkansas. The U.S. Geological Survey is currently assessing the technically recoverable hydrocarbon resources of the Arkoma basin and for assessment purposes has divided the continuous shale gas (unconventional) resources into three total petroleum systems together with their associated assessment units (AUs). Each of the gas shale AUs contains 2.5 % or more total organic carbon, is thermally mature with respect to gas generation over much of its area within the basin, and may be accessed by the drill at depths less than 14,000 feet. In addition, the Woodford, Caney, and Fayetteville Shale Gas AUs underlie relatively large areas that have not been tested adequately by the drill. Coal-bed gas is currently being produced from the Hartshorne and McAlester coal beds in the Arkoma basin, and for assessment purposes they have been grouped together into one total petroleum system and one AU. Much of the area where the coal beds are relatively shallow in the northern part of the AU has been drilled. However, the area underlain by coal in the southern part of the basin, which is deeper and more structurally deformed, remains largely unexplored for coalbed methane.

Unconventional Seals for Unconventional Gas Resources: Examples from Barnett Shale and Cotton Valley Tight Sands of East Texas

Chaouche, A.
Anadarko Petroleum Corporation.
Ahmed.Chaouche@anadarko.com

Abstract

Assessment of undiscovered oil and gas resources is based on geological elements and processes of a petroleum system. Application of the petroleum system in the oil industry varies largely on how the processes of hydrocarbon generation, migration, and entrapment are described. It is often depicted as a relationship between source and reservoir rocks connected by fluid paths (*e.g.*, carrier beds, faults, *etc.*) through geological time. When appropriate conditions (time, temperature, and trap formation) are reached, the effort is focused on secondary migration from source to reservoir. Secondary migration efficiency is a function of the distance between source and reservoir rocks. Tertiary migration (or dismigration) refers to fluid movement from reservoir to reservoir and involves migration pathways (fault or sand beds and/or unconformities).

There has been much research on source rock quality and its relationship to hydrocarbon potential. Much less has been documented about the rate, mechanisms, and pathways by which gases migrate through kilometer-scale sequences of fine-grained sediments. Mass balance calculations supported by laboratory experiments on good quality source rocks show that significant volumes of hydrocarbons can be generated and expelled from the source rock, but exploration results show that only a small fraction (<10%) is trapped within conventional reservoirs. Dispersion in the carrier beds (10 to 20%), retention in the source rock (30 to 40 %), dismigration (10 to 20%), and biodegradation (10 to 20%) are commonly assumed to be the altering mechanisms of the bulk fluid generation. The proximity of source rock and reservoir rock becomes critical to fluid preservation and accumulation.

The unconventional Barnett Shale and Cotton Valley Tight Sands of East Texas are no different from other petroleum systems. The Barnett Shale is a classic shale gas system that includes the elements of source, reservoir, and seal. The Cotton Valley Formation (CVF) exhibits an inter-fingering shale/sand system that juxtaposes source and reservoir offering preservation and high migration efficiency.

Occurrences of sweet spots in Barnett Shale are related to the original source rock richness, maturity, and confinement of the source beds. The Fort Worth basin of East Texas is asymmetric and has a polyphased burial history. Its western part along the Washita high has undergone uplift and erosion at the Miocene. The resulting liable asphaltenes precipitation has created a permeability barrier within the shale preventing gas from escaping laterally to the west. The lower Barnett encased between the Marble Falls Limestone and the Chappel Limestone has limited gas leakage to the top and the bottom, creating an optimum seal for the Newark Field where the highest gas production per well has been observed. Laminated carbonates and chemically induced carbonate nodule deposits in the early organic diagenesis provide vertical and lateral baffles to fluid flow thus enhance the confinement within the most productive Barnett Shale.

In the Cotton Valley Formation, significant permeability reduction occurs within the inter-fingering shale and tight sands. The migration of oil from shale to sand has accumulated a significant volume of oil that ultimately has cracked to gas when burial reached the gas window in the Cotton Valley. This secondary cracking has resulted in high pressures extending far beyond the source rock, flushing the interstitial water to overlaying formations. Different chemical water mixes has lead to mineralization and thus diagenetic seals enhancing confinement, which has result in stair-step pressure offsets occurring independently of lithology profiles.

Lithostratigraphy and Petrophysics of the Devonian Marcellus Interval in West Virginia and Southwestern Pennsylvania

Boyce, Matthew L.
Dept of Geology and Geography
West Virginia University
98 Beechurst Ave., 330 Brooks Hall
Morgantown, West Virginia 26505
mboyce5@mix.wvu.edu

Carr, Timothy R.
Marshall Miller Professor of Geology
West Virginia University
98 Beechurst Ave., 330 Brooks Hall
Morgantown, West Virginia 26505

Abstract

In the Appalachian basin, the Middle Devonian organic-rich shale interval, including the Marcellus Shale, is an important target for exploration. This unconventional gas reservoir is widespread across the basin and has the potential to produce large volumes of gas (estimated to have up to 1,307 trillion cubic feet of recoverable gas). Although the Middle Devonian organic-rich shale interval has significant economic potential, stratigraphic distribution, depositional patterns and petrophysical characteristics have not been adequately characterized in the subsurface. Based on log characteristics, tied to core information, the lithostratigraphic boundaries of the Marcellus and associated units were established and correlated throughout West Virginia and southwestern Pennsylvania. Digital well logs (LAS files) were used to generate estimates of lithology and to identify zones of higher gas content across the study area. In addition, a lithologic solution was calibrated to X-ray Diffraction (XRD) data. Using previous studies on organic shale, relationships between the natural radioactivity (as measured by the gamma-ray log) were incorporated with techniques to identify gas-prone intervals. The comparison between the Uranium content and the measured bulk density identified intervals in the Marcellus having high gas saturations and were used to generate an approach to correct water saturations. These techniques of identifying lithology and potential gas in the Marcellus are useful to identify areas of higher exploration potential and to target zones for fracture stimulation or to land a horizontal leg.

Estimating Resources and Reserves in Coal-Bed Methane and Shale Gas Reservoirs

Jenkins, Creties
DeGolyer and MacNaughton
5001 Spring Valley Road, Suite 800E
Dallas, Texas 75244

Abstract

In the past two decades, production from coal-bed methane and shale gas reservoirs has more than doubled in the United States and now provides about 16% of total annual gas production. Estimating resources and reserves in these reservoirs is challenging and requires a thorough understanding of (1) the factors that control the storage, distribution, and production of this gas, (2) the data required to properly characterize these reservoirs, (3) the techniques used to forecast well and reservoir performance, and (4) the rules and guidelines governing the assignment of resources and reserves.

It is important not just to estimate proven reserves, but all reserves and resources classes in order to capture the full spectrum of development opportunities. Accurate estimates require detailed information, but since little of this may be available, it is up to the evaluator to exercise good judgment and apply techniques that capture the inherent uncertainty in the estimates. It is also important to recognize that the rules, guidelines, and techniques are still under development for unconventional gas, and that it may be several years before consistent procedures are applied throughout the industry.

Developing Exploration Strategies for Coal-Bed Methane and Shale Gas Reservoirs

Scott, Andrew R.
Altuda Energy Corporation
San Antonio, Texas
andrew@altuda.com

Abstract

Coal and shale reservoirs are playing a progressively more important role in unconventional natural gas production and reserves in the United States and worldwide. Shale gas and coal-bed methane now represent 19.4 percent of total dry natural gas production in the United States and 21.9 percent of gas reserves. Shale gas production and reserves exceeded coal-bed methane for the first time in 2008. At first glance coal and shale reservoirs appear to have few similarities and are often treated as separate entities in terms of exploration strategies. Although there are certainly differences between these two reservoir systems, they also have a number of similarities indicating that many, but not all, of the exploration concepts developed for identifying coal-bed methane sweet spots may also be applicable to shale gas reservoirs.

Both coal seams and shale reservoirs are characterized as fractured systems in which the microporous, organic fraction of the coal and the clay and mineral shale matrix have nearly zero permeability. Gas and fluid migration occur through naturally occurring fractures (cleats) in coals and either natural or induced fractures in shales. Natural gas is sorbed to the organic matter in both the coals and shales, but the coals contain more sorbed gas per ton than the shales due to a higher organic content. However, in addition to sorbed gas, shale reservoirs have additional gas stored within the mineral matrix which contributes to additional total gas in the system. This free matrix gas compensates for the lower organic content (relative to coals), and therefore, sorbed gas in shale reservoirs.

Most coal-bed methane wells occur at depths less than 3,000 feet due to permeability restrictions, but the deepest coal-bed methane wells in the world produce from 7,500 feet in the Piceance Basin. Shale gas wells range between 500 feet in the Antrim Shale to 12,000 feet in the Woodford and Haynesville/Bossier shales. Coal and shale reservoirs may contain nearly 100 percent thermogenic or secondary biogenic gases and, regionally, will have a mixing zone that contains both thermogenic and biogenic gas components. Exceptionally high production rates for both coal seams and shales require a certain minimal level of thermal maturity: 0.8 to 1.0 percent in coal beds and more than 1.0 to 1.2 percent in shales.

Recovery factors in coal reservoirs is highly variable ranging from more than 80 percent in high permeability coals to less than 15 percent in lower permeability coal seams; coal seams with less than 1 md permeability are generally not economical. Most commercial coal beds have recovery rates between 30 and 60 percent. Shale gas recovery rates appear to be generally lower than in coal beds, generally ranging between 10 and 20 percent, but recovery rates in the Antrim Shale have been reported to be as high as 60 percent. However, recovery factors for shale reservoirs is more complicated than for coal reservoirs due to the combination of sorbed and matrix gas. Therefore, published recovery factors for many shale plays are still being evaluated indicating that the final range of recovery rates may vary significantly from what is predicted today.

The six key hydrogeologic factors affect coal-bed methane producibility are depositional systems, tectonic/structural setting, coal rank or thermal maturity, gas content, permeability, and hydrodynamics. If all six factors come together in a synergistic way, then exceptionally high coalbed methane producibility may result.

This model was initially developed from three end-member basins that had markedly different properties: (1) Piceance, (2) Powder River, and (3) San Juan basins. The Piceance Basin was characterized by high thermal maturity coal seams (vitrinite reflectance, VR, values exceeding 1.0 percent), exceptionally high gas content (more than 700 scf/ton) values, and low permeability (generally less than 1 md). This low permeability results in marginal production rates over

much of the basin. The Powder River Basin is characterized, by thick, laterally extensive coal seams (individual seams >100 ft thick), low thermal maturity (VR values generally <0.5 percent), and low gas content values (generally <32 scf/ton).

However, the presence of exceptionally thick coal seams at shallow depths make drilling costs lower and the economics much better than the Piceance Basin despite the low levels of thermal maturity and gas content values. Therefore, the Piceance Basin represents a high thermal maturity play characterized by predominantly thermogenic gases, whereas the Powder River Basin is recognized as a secondary biogenic coalbed methane play with lower levels of thermal maturity and corresponding gas content ranges.

The prolific San Juan Basin represents an intermediary between the Piceance and Powder River basins. The San Juan Basin is characterized by thick (up to 90 ft net coal) laterally continuous coals of high thermal maturity (VR values 0.80 to 1.5 percent, northern basin). Fresh, meteoric water transported basinward through permeable coal beds has carried microbes that have bioconverted the coal and thermogenic, wet gas components into secondary biogenic methane. This has resulted in fully saturated coals and exceptionally high gas content values (>600 scf/ton) where meteoric recharge has occurred in the northern part of the basin.

These same six hydrogeologic factors can also be applied to shale reservoirs, although the tectonic and structural setting, rock properties, and completion techniques appear to be much more important in shale reservoirs than in coals. As in coal reservoirs, shale gas plays can be characterized using two end members: (1) the Barnett Shale, and (2) Antrim shale, which correspond with the thermogenic (Piceance-type) and secondary biogenic (Powder River-type) plays, respectively. An intermediary, San Juan-type play has not been clearly identified in shale gas plays to-date, but such an intermediary play probably will be less productive than the Barnett Shale due to the physical differences between shale and coal reservoirs. Just as in coal-bed methane, a detailed understanding of the hydrodynamics of the reservoir system will be required to identify potential sweet spots associated with upward flow potential. This is particularly true for the Antrim- and intermediary-type shale gas plays, but understanding hydrodynamics, and the distribution of hydrocarbon and artesian overpressure is an overlooked but important component of shale gas plays.

Getting Natural Gas Out of Shales and Coals

Palmer, Ian
Higgs-Palmer Technologies
Albuquerque, New Mexico 87114
ian@higgs-palmer.com

Abstract

This paper will discuss some established procedures and recent learnings in regard to well completions and production in both shale gas and coalbed methane reservoirs. The talk will address certain commonalities, peculiarities, and challenges of both. Some of the technical aspects will include the importance of natural fractures and permeability, examples of commercial production, and optimizing well stimulation. The approaches and learnings from coals and shales may be transferable to newer unconventional resources.

Implications of Variable Gas Saturation in Coalbed Methane Reservoirs of the Black Warrior Basin

Pashin, Jack
Geological Survey of Alabama
P.O. Box 869999
Tuscaloosa, Alabama 35486-6999
jpashin@gsa.state.al.us

Abstract

Variable gas saturation in coal of the Black Warrior basin has significant consequences for production performance, and the relationship of gas saturation to isotherm geometry is a critical consideration for development. Although gas content generally increases with depth, saturation typically vari‘es greatly among individual coal seams. Reservoir conditions in the Black Warrior basin are the product of a complex mix of stratig 22raphic, structural, hydrogeologic, and petrologic factors, and these factors have a strong influence on the mobility and recoverability of coalbed methane. In deep, highly pressured seams that are substantially above Langmuir pressure, the low slope of the isotherm indicates that even minor undersaturation can necessitate prolonged dewatering before the reservoir reaches critical desorption pressure. Where reservoir pressure is relatively low and the slope of the isotherm is relatively steep, by contrast, reservoirs that are significantly undersaturated with gas can be close to the critical desorption pressure. Consequently, low reservoir pressure in the northern part of the Black Warrior coalbed methane play favors high gas recovery from all coal seams, whereas recovery from deep, highly pressured coal in the southwestern part of the play is favored by a combination of high initial gas content and high Langmuir pressure.

Coal-Bed Natural Gas Production and Gas Content of Pennsylvanian Coal Units in Eastern Kansas

Newell, K. David
Kansas Geological Survey
University of Kansas
Lawrence, Kansas

Carr, Timothy R.
Department of Geology and Geography
West Virginia University
Morgantown, West Virginia

Abstract

Middle Pennsylvanian coal units in eastern Kansas produce commercial quantities of coal-bed natural gas. Annual coal-bed natural gas production in 2008 was 49.1 billion cubic feet (Bcf) (13% of state output); cumulative production since 2000 is 165 Bcf. Coal beds are commonly less than two feet thick and are mostly produced by vertical wells at 80- to 160-acre spacing. Wells usually have comingled gas production from several coal beds. The main producing region is a four-county area (Labette, Montgomery, Neosho, and Wilson counties) in southeastern Kansas immediately north of the Oklahoma state line. Most wells are not prolific; their average maximum production rate is approximately 67 mcf/day, peaking about 14 months after initial production. Decline rates are low, as some coal-bed natural gas wells have produced 15 years and beyond. North-northwest–south-southeast trending production fairways can be defined by mapping maximum production rates. These fairways generally correlate to where coal beds are individually and compositely thick. The most prolific wells in the thickest coal units record maximum production rates as great as 615 mcf/day.

The median as-received gas content for coals in southeastern Kansas is 139 scf/ton, with maximum gas content of approaching 400 scf/ton. Gas content in east-central and northeastern Kansas coal beds generally runs half that of southeastern Kansas, indicating economics of coal-bed natural gas production are harsher northward. Coals increase in depth westward at a rate of approximately 20 feet per mile. Their gas content commensurately increases by 10 to 20 scf/ton for each 100 feet of burial. Thin (<4 foot) black shale beds interbedded with the coal units may have commercial potential, for their as-received gas content can be great as 65 scf/ton, but 20 scf/ton is the median of all shale samples assayed.

Prospects and Progress in the Green River Formation Oil Shale, Western United States

Carroll, Alan R.
Department of Geoscience
University of Wisconsin
1215 W. Dayton St.
Madison, Wisconsin 53706
carroll@geology.wisc.edu

Abstract

The Eocene Green River Formation has long been believed to contain the world's largest commercial oil shale deposits, having a recently estimated *in situ* resource of 2 trillion barrels of oil. Most of this resource lies within the Piceance Creek basin in northwestern Colorado, but additional oil shale intervals also occur within the Uinta basin in Utah and the greater Green River basin in Wyoming. The smaller reported magnitude of resources in Utah and Wyoming reflects thinner stratigraphic intervals but may also be due in part to more conservative assessment approaches (Utah) or to less complete assessment data (Wyoming).

The Green River Formation represents the deposits of long-lived lakes that occupied several intermontane basins within the broken "Laramide" foreland. Oil shale facies consist dominantly of carbonate-rich mudstone, having organic enrichment reaching up to 60 gallons of oil per ton (Fischer Assay). Lithofacies assemblages record a wide range of depositional conditions that define three major lake basin types. Under-filled lake basins often contain bedded evaporites deposited by hypersaline lakes, and their stratigraphy is dominated by aggradational lake cycles. Identifiable fossils are typically absent, but mudstone facies may be highly enriched in organic matter due to high algal and cyanobacterial productivity. Balanced-fill lake basins contain lakes of fluctuating salinity that may reach brackish or fresh water conditions. Rich oil shale deposits and fish fossils are common, and their stratigraphy reflects a mix of aggradational and progradational geometries. Over-filled lake basins contain fresh water lakes, and their stratigraphy is dominated by shoreline progradation processes. Coal and carbonaceous shale are common, often associated with mollusks and other freshwater fauna. Oil shale can be present but is often of relatively low grade.

Volcanic tuff horizons interbedded with lacustrine strata have recently helped to establish an extensive chronostratigraphic framework for the Green River Formation. Radioisotopic dating of these tuffs (at temporal resolution of ~100 ky) indicates that the Green River Formation spanned more than 8 million years, from <52 ma to >44 ma. Different lake types often occupied adjacent basins at the same time, indicating that fill and spill relationships were as important as climate in determining paleoenvironmental conditions and oil shale quality. Major lake-type transitions appear to have been caused by changes in regional drainage organization. For example, expansion of the Mahogany oil shale across the Piceance Creek and Uinta basins appears to have occurred in response to capture of a mountain river in central Idaho. This river flowed into Lake Gosiute in Wyoming, which in turn spilled into Colorado and Utah.

Large-scale commercial production of Green River Formation shale oil depends on resolving two significant problems: production costs, and potential environmental impact. Both concerns are currently being addressed through the development of new in situ retort techniques. These techniques involve slow heating of oil shale (to temperatures near 700°F), with the aim of directly producing relatively high quality light oil. In contrast to conventional mining and surface retort, asphaltenes and other potentially harmful components are retained in the subsurface. Requirements for process water are also greatly reduced.

At last three distinctly different *in situ* retorting methods are being developed for use in the Piceance Creek basin. The Shell *In Situ* Conversion (ICP) process uses vertical heating and production wells, with containment by an outer freeze-wall. Heating is accomplished by an electrical resistance element, and the freeze-wall is maintained by injection of chemical

refrigerant into an outer ring of wells spaced approximately 8 ft apart. In contrast, ExxonMobil's method utilizes horizontal wells and hydraulic fracturing of the oil shale. Heating will be accomplished using a conductive proppant material (calcined petroleum coke), to which an electrical current will be applied. Finally, the American Shale Oil Company (AMSO) plans to use inclined wells, drilled below the stratigraphic level of Piceance Creek basin evaporite minerals. All three methods are currently undergoing field tests.

The History of US DOE Unconventional Energy Resources in the US, An Archive of References Available for Application to Current Oil Shale and Tar Sand Resources

Mroz, Thomas H.
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, West Virginia 26507

Abstract

The US Department of Energy (DOE) has participated in a large number of energy projects related to all aspects of conventional and unconventional energy research over the last four decades. Resources addressed in these projects include secondary and tertiary enhanced oil recovery, coal-bed methane, tight sands, oil shale, tar sands, gas shale, gas hydrates and deep gas. The current projects at the National Energy Technology Laboratory include enhanced oil recovery, oil shale and tar sands, deep gas, and gas hydrates. The information presented in this paper is related to the historic projects and the results from case studies, production mechanisms, environmental aspects, and technology development producing results that reduced the costs of locating, evaluating, and producing these resources in the US, during the last forty years. The information is available through the DOE web site, http://www.netl.doe.gov. Included on the website are links to the University of Utah and the Colorado School of Mines for access to further references related specifically to oil shale and tar sand research.

Tight-Gas Sandstone Reservoirs: The 200-Year Path from Unconventional to Conventional Gas Resource and Beyond

Coleman, James
U.S. Geological Survey
Mail Stop 956 National Center
12201 Sunrise Valley Drive
Reston, Virginia. 20192

Abstract

The evolution of tight-gas sandstones from unconventional to conventional gas reservoirs in the United States began with hydrocarbon exploration and production from the Appalachian Basin during the first half of the 19th century, when brines were the preferred product, and petroleum was the unconventional and generally undesired product. During the next 100 years, rapid development of petroleum extraction and delivery technology fed an increase in petroleum demand, such that low flow-rate reservoirs were uneconomic and unable to meet the national need. These low-flow rate reservoirs were rejected in favor of high flow-rate reservoirs in California, the Midcontinent, and the Gulf Coast. Even then, vast amounts of natural gas were flared off or vented, because no market existed for much of this produced gas.

With each successful discovery from these areas, the U.S. natural gas supply progressively exceeded demand and pipeline deliverability throughout the first half of the 20th century. In response to the "energy crisis" of the 1970's, the Federal government removed price controls on interstate natural gas in 1978 and created new tax incentives in 1980 to help offset the cost of drilling and producing unconventional gas reservoirs, including tight-gas sandstones. These decisions helped spawn a new industry and prompted geoscientists to examine the geological conditions that created and preserved large volumes of natural gas in low-permeability reservoirs.

Tight-gas sandstone reservoirs exist in a wide variety of settings, ranging from simple one-well accumulations to complex montages of multilayered sand bodies requiring thousands of wells to develop. They may have a reasonably well-defined geologic limit or appear to have no spatial association with any easily discernible mappable geologic phenomena. Understanding the true nature and future potential of yet-to-be-developed, tight-gas sandstone reservoirs is essential for the nation to supply its annual need for gas for the 21st century.

Many Technologies Applied to Develop Wattenberg Field, a Giant in Denver's Backyard

Birmingham, Thomas J.
Anadarko Petroleum Corporation
1099 18th St. #1800
Denver, Colorado 80202

Abstract

Since its discovery in 1970, Wattenberg has been a prolific oil and gas field in the Rocky Mountain region. Having 4.2 TCFE produced to-date and estimated EURs conservatively projected to exceed 5.5 TCFE, Wattenberg ranks as the 8th largest gas field in the U.S. Production was first established from the Cretaceous J Sandstone, a pervasive delta-front shoreline and valley fill sequence covering a significant portion of northeast Colorado. In the early 1980's, commercial production from the Cretaceous Codell and Niobrara formations established low-risk multiple pay options over the entire field area, which underwent strong exploitation phases during the 1990's and 2000's. The Codell represents marine shelf bar and bar margin sandstone deposits. The Niobrara is represented by a deep water chalk environment of deposition. All producing units in Wattenberg are classified as tight gas reservoirs, having *in situ* permeabilities ranging from 0.01 to 0.0001 md and requiring hydraulic fracture stimulation to achieve commercial results.

Multiple generations of technological improvements in drilling, petrophysics, and completion practices have been applied in Wattenberg during four decades of field development. Operational and logging methods include directional and pad drilling, horizontal drilling, infill drilling, FMI, CMR, and ECS logging, and new commingling of pay groups. Reservoir methods include advances in hydraulic fracturing, microseismic evaluations, petrophysical/saturation modeling, facility automation, subsurface ties to outcrop sections, pressure/volumetric studies, and fault sealing analyses. More recent studies tying outcrops to subsurface sections of isolated shelf sand bodies may provide potential opportunities for new generation plays and increase current reserve estimates.

In the future, Wattenberg will continue as a major gas field. Its proximity to the metropolitan corridor in eastern Colorado will provide that area with a convenient low-cost source of energy supply.

Geology of the Piceance Mesaverde Gas Accumulation

Cumella, Stephen P.
Bill Barrett Corporation
1099 18th Street, Suite 2300
Denver, Colorado 80439

Abstract

Aggressive development of the Mesaverde gas accumulation in the Piceance Basin over the past decade has demonstrated that a commercial gas resource is present in much of the deeper part of the basin. Unlike tight gas resources in some other basins (*e.g.*, the greater Green River Basin), commercial production doesn't appear to be limited to specific fairways or sweet spots. There appears to have been a sufficient gas source within *in situ* coals and underlying marine shales to pervasively gas charge up to 3500 ft of the Mesaverde. An extensive vertical fracture system has resulted from over pressuring from hydrocarbon generation. Laramide tectonic fractures are also locally abundant. This fracture system has enabled vertical gas migration within an otherwise very low permeability system.

In spite of being one of the oldest areas of tight gas production in the Rocky Mountain region, innovations in drilling and completion technology continue to expand the area of commercial production. Directional drilling has allowed over 20 bottom-hole locations to be accessed from a single surface location, and laterals reach up to 5000 ft. Microseismic imaging of hydraulic fracture stimulation has helped place bottom-hole locations optimally with regard to highly elliptical drainage patterns. Large water volume hydraulic fracturing has dramatically improved estimated ultimate recoveries (EURs) of wells in some areas. Also, unconventional pay picking has added significant resources that were not previously developed.

Fracture Diagenesis and Producibility in Tight Gas Sandstones

Laubach, Stephen E.
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924, USA
steve.laubach@beg.utexas.edu

Olson, Jon E.
Department of Petroleum & Geosystems Engineering
Cockrell School of Engineering
The University of Texas at Austin
1 University Station C0300
Austin, Texas 78712, USA

Eichhubl, Peter
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924, USA
peter.eichhubl@beg.utexas.edu

Abstract

Fractures in tight gas sandstone remain challenging to characterize or predict accurately. Here we recapitulate recent work on continuity of fracture porosity and its important effect on fluid flow. Natural cement precipitation (diagenesis) in fractures can preserve fluid conduits by propping fractures open or otherwise reducing stress sensitivity of fracture permeability. It can also impede fluid flow by reducing effective fracture length, or occluding porosity. We report patterns of natural fracture growth and decay that are extensively influenced by diagenesis. These patterns typify many fractured siliciclastic and carbonate rocks. We show how appreciation of diagenetic effects can be used to improve accuracy of predictions of fracture attributes and illustrate implications for fluid-flow simulation. Our results also imply that fractures will not tend to close under subsurface loading conditions in many tectonic settings. Chemical alteration and the interactions of diagenetic reactions with rock properties and the *in situ* stress dictate the location of open fractured flow conduits.

Case Studies Examining the Discovery Sequence and Gas Accumulations in Tight-Gas Sandstones

Coleman, James
Attanasi, Emil
U.S. Geological Survey
Mail Stop 956 National Center
12201 Sunrise Valley Drive
Reston, Virginia. 20192

Abstract

An examination of the geologic characteristics and discovery history of seven plays, which were originally classified by the U. S. Geological Survey (USGS) in 1995 as continuous-type gas sandstone plays, shows that these plays have a high degree of similarity with conventional discrete accumulations in terms of reservoir continuity, sand body geometry, and trapping configurations. The general decline in discovery size with increasing numbers of discoveries suggests a means to put limits on volumes of resources assessed in un-drilled areas of a particular play.

Routine time-series analyses of conventional plays typically show a decline in field discovery size as each subsequent discovery within the play trend is announced. If gas accumulations in low-permeability sandstone plays occur in trap settings typical of discrete conventional accumulations, then modeling of the discovery sequences within plays may provide an effective way to constrain regional estimates of remaining recoverable resources. At the other extreme, if the play is regarded as a single homogeneous continuous entity (albeit, with some "sweet spots"), only the play boundary constrains the number of un-drilled sites that could contribute to remaining recoverable resources, and there should be no general decrease in discovery size.

The seven continuous-type gas sandstone plays selected for this study had a sufficient number of observations to test whether discovery size correlates with sequence of discovery. These showed that discovery size tends to decline with sequence of discovery and in three of the seven the trend was statistically significant. The discovery size rank and sequence relationship was found to be similar to several well known conventional plays.

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