AVAILABILITY, ECONOMICS, AND PRODUCTION POTENTIAL OF NORTH AMERICAN UNCONVENTIONAL NATURAL GAS SUPPLIES

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1 EXECUTIVE SUMMARY

1.1 Introduction

North American natural gas production in recent decades has been characterized by an increasing contribution from unconventional gas. Unconventional gas is differentiated from conventional gas on the basis of the nature of the geologic reservoirs it is found within and the types of technologies required to extract the gas. **Conventional natural gas deposits** have a well-defined areal extent, the reservoirs are porous and permeable, the gas is produced easily through a wellbore, and reservoirs generally do not require well stimulation to produce. **Unconventional natural gas deposits** are very diverse and difficult to characterize overall, but in general are often lower in resource concentration, more dispersed over large areas, and require well stimulation or some other extraction or conversion technology. They also are often more expensive to develop per unit of energy.

Research and investment into unconventional gas resources has increased significantly in recent years due to the higher price environment for natural gas. In several cases, the technologies for economic production have already been developed, while in other cases, the resources are still in the research stage.

The three types of unconventional natural gas that contribute significantly to U.S. natural gas production today are tight gas, coalbed methane, and shale gas. (See Section 1.2 for resource definitions). Extremely large gas-in-place volumes are represented by these resources, and the U.S. has produced only a fraction of their ultimate potential.

North America contains large quantities of unconventional natural gas resources in the form of **tight gas**, **coalbed methane**, and **shale gas**.

While unconventional natural gas has been a significant component of U.S. production for a long time, its contribution has grown rapidly in recent years. Notable trends include the growth in production from tight gas reservoirs in the Rockies and East Texas, coalbed methane in Wyoming and New Mexico, and shale gas in North Texas and the Mid-Continent region.

The most significant trend in U.S. natural gas production is the rapid rise in natural gas production from shale formations.

The growing production from the Barnett Shale in the Fort Worth Basin of North Texas and the more recent startups of the Fayetteville and Woodford Shale plays in the Mid-Continent region have shown the greatly improved production potential of horizontal drilling and stimulation technologies. Many of the advances made in these technologies have come just within the past decade. This year, numerous company announcements have been made about North American horizontal drilling shale gas plays. These include the Haynesville Shale in Northern Louisiana, the Marcellus and Huron Shales in Appalachia, the Pearsall Shale in Texas, the Utica Shale in Quebec, and the Horn River Basin and Montney Shale in British Columbia. It appears certain that shale gas production will expand in coming decades, and production will emerge in new regions in the U.S. and Canada.

ICF is forecasting that tight gas, coalbed methane, and shale gas will make a major contribution to future North American gas production. Total North American natural gas production is forecast to increase from 25 Tcf in 2007 to almost 29 Tcf by 2020.

This production growth will be driven by onshore unconventional gas. The unconventional percentage of gas production is forecast to increase from 42 percent in 2007 to 64 percent in 2020. Although this report focuses on the period through 2020, our modeling indicates that unconventional gas production will continue to increase beyond 2020 in both volume and percentage terms.

In addition, other forms of unconventional gas also exist. In many cases, these resources represent additional huge quantities of gas-in-place that could be targeted for commercial development.

Other forms of unconventional gas will contribute at a modest level through 2020, including aboveground coal gasification (with nine plants currently planned, representing over 400 Bcf per year of gas production), landfill gas (the potential for 800 Bcf per year of methane by 2020), and biogas (tens of Bcf by 2020).

The fall 2008 credit crisis, stock market collapse, and oil and gas price decline may lead to reductions in gas drilling programs planned by producers. However, the long-term need for energy in the U.S. and Canada should be strong enough to support the future gas production levels shown in this report, albeit on a possibly slower pace.

1.2 Resource Definitions

Natural gas resources may be classified as **"conventional"** or **"unconventional."** **Conventional natural gas resources** are defined here as quantities of natural gas or oil that occur in discreet accumulations in generally higher porosity and permeability reservoir rocks and that are developed and produced using standard drilling and completion technologies. **Unconventional natural gas resources** are typically much lower in resource concentration, are more dispersed, and require well stimulation or other technologies to produce. They are divided here into two broad categories: **(1) Unconventional Natural Gas in Low-Quality Reservoirs, and (2) Unconventional Natural or Synthetic Gas Processed from a Non-Gaseous State.**

The first category of unconventional gas contains resources that are currently contributing significantly to U.S. gas production, although development methods and technologies continue to evolve. These resources are described as follows:

Unconventional Natural Gas in Low-Quality Reservoirs

Definition: *Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.*

Tight Gas is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

Coalbed Methane is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

Shale Gas is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale formations with certain characteristics will produce gas.

Shale Oil with Associated Gas is defined as associated gas from oil shale in horizontal drilling plays such as the Bakken in the Williston Basin. The gas is produced through boreholes along with the oil.

The second category of unconventional gas resources contains resources that are either contributing little production because of economic or other factors, are still in the research stage, or are being evaluated through pilot projects. They require some process to convert organic matter into methane and other gaseous fuels. These resources are described as follows:

Unconventional Natural or Synthetic Gas Processed from a Non-Gaseous State

Definition*: Other forms of hydrocarbons that either do not currently exist in a gaseous state amenable to conventional production methods, or that require advanced processes and approaches to produce a fuel-grade hydrocarbon gas.*

Gas from Thermal Oil Shale is defined as gas processed through the thermal distillation of kerogen in oil shale, such as the Green River Formation in Colorado, Utah, and Wyoming.

Offshore and Arctic Gas Hydrates are defined as ice-like solids in which methane is trapped in water molecules in a cage-like molecular structure. They are found in both deepwater and arctic settings.

Aboveground Coal to Methane is defined as the conversion of coal to methane through surface processing in a coal gasification plant.

Underground Coal to Methane is defined as the conversion of *in-situ* or underground coal to methane.

Landfill Gas is defined as methane generated by the decomposition of organic waste in a disposal facility or landfill.

Biologic Methane is defined as the production of methane through (1) agricultural biogas (the anaerobic digestion of agricultural byproducts), (2) digester biogas (the anaerobic digestion of manure), and (3) wastewater treatment biogas (methane from the anaerobic digestion of wastewater sludge).

1.3 Objectives

This study evaluates the potential of North American unconventional natural gas sources. Changes in basin and region production rates resulting from the emergence of new high volume gas plays could have a large impact on the North American natural gas transportation industry.

Objectives of the study include the following:

- Description of the types of unconventional gas that might be relevant for U.S. and Canada through 2020
- Determination of the location where such gas might be produced
- Estimation of the supply volumes potentially available from each type and location
- Evaluation of typical project lead times and timing for future resource development
- Discussion of gas quality issues
- Estimation of the resource cost of each type of unconventional gas
- Discussion of constraints for resource development including land access, environmental permitting, production technologies, lead times, capital costs, and market environment.

This study does not examine the infrastructure needed to bring this new supply to market. Required natural gas infrastructure is the subject of another report ICF will prepare for the INGAA Foundation in 2009.

1.4 Major Conclusions of Study

- After years of relatively constant or declining production, U.S. natural gas production is increasing, due largely to increased unconventional natural gas production. (Section 4).

- Through 2020, North American natural gas production will come increasingly from tight gas, coalbed methane, and shale gas reservoirs. Unconventional natural gas production will increase in both the Lower-48 and Canada. (Section 4).

- As industry has made a large-scale shift toward development of unconventional natural gas, the underlying cost of U.S. natural gas reserve additions has gone up. While this implies that long-term prices will remain higher than in previous years, the large resource base means that there is more assurance that future domestic natural gas supplies will be adequate. (Section 7).

- 2008 has seen the emergence of several new shale gas plays in both the U.S. and Canada. Both countries will see large regional production increases from these plays. These supply changes are expected to have significant implications for the gas transportation industry, in terms of capacity growth and de-bottlenecking. (Section 6).

- An updated resource base of remaining natural gas resources in the U.S. and Canada is presented here. This resource base includes preliminary estimates for the emerging shale plays. Total natural gas resources in North America exceed 2,300 trillion cubic feet (Tcf). Shale resources alone within this assessment total over 500 Tcf of recoverable natural gas. To put this in perspective, annual U.S. and Canada gas production in 2007 was approximately 25 Tcf. For the Lower-48, tight gas is assessed at 174 Tcf, coalbed methane at 65 Tcf, and shale gas at 385 Tcf. (Table 7, Section 5).

- The assessment of shale gas potential in the U.S. and Canada is a work in progress and there is a long way to go to understand remaining potential and implications for future natural gas production. The rapid advance of drilling and completion technology has opened up plays in a number of different basins that were not previously considered to have economic potential. The volumes of gas-in-place are extremely large, and a small difference in the estimated percentage of gas-in-place that is recoverable has a huge impact on estimates of recoverable resources.

- Lower-48 natural gas production is forecast to increase from 19 Tcf per year in 2007 to 23 Tcf per year in 2020. During this period, the percentage of Lower-48 unconventional natural gas will grow from 48% to 69% of total Lower-48 production. (Section 4).

- Canadian natural gas production is forecast to decline slightly from 6.6 Tcf to 5.7 Tcf per year by 2020. However, the contribution of unconventional natural gas production will increase from 24% to 43% of natural gas production. (Section 4).

- The natural gas production forecast presented here projects higher levels of future natural gas production than that of the 2008 EIA Annual Energy Outlook, which forecasts only a slight increase in Lower-48 gas production and relatively flat unconventional gas production. The forecast presented here is for a Lower-48 production level of 23 Tcf per year by 2020, in contrast to the EIA forecast of 18 Tcf. (Section 4).

- Environmental and regulatory issues will likely impact the development of unconventional resources. These include well and environmental permitting and related costs, land access, water use and disposal, and surface disturbance. Water use and disposal for fracturing of shale wells has already emerged as a significant issue, although, to date, water use has not significantly restricted development in most shale areas.

- To achieve the gas production forecast presented here, it will be necessary to drill an average of approximately 25,000 unconventional gas wells per year through 2020. That equates to 300,000 wells, representing a drilling and completion cost outlay of $560 billion. To achieve the forecast results, industry must have land access for drilling, a reasonable permitting process, and adequate prices and demand for natural gas. The forecast incorporates assumptions in these areas, but there are uncertainties involved.

- Our forecast may prove to be conservative, especially for gas shales. This is because the size of the recoverable resource base is large enough to support higher levels of annual production over the long term if such production is demanded by the market. In addition, it is likely that our forecast for Western Canada is conservative, given the limited available information on new shale plays in British Columbia. Also, several emerging shale plays, such as those in the southeastern U.S. and the Rocky Mountains, are not included here due to the scarcity of available information. (Section 4).

- The chemical composition of natural gas from unconventional sources is an important consideration for the transportation and processing industry. There is significant variability in gas composition among unconventional plays, even within a specific play. Gas "wetness" or the ratio of heavier hydrocarbons to methane is an issue in the Barnett Shale, requiring significant gas liquids processing. There is a general lack of public gas composition data for major unconventional gas plays. (Section 5).

- The available resource base for aboveground coal gasification is in the thousands of Tcf. Large scale plants have the most favorable economics, generally in a range of $7 to $9 per million Btu (MMBtu). Significant environmental issues include mining issues and greenhouse gas emissions. Greenhouse gas legislation requiring carbon sequestration or the payment for greenhouse gas allowances could result in significant cost increases. Nine aboveground gasification plants are planned in the U.S. and Canada, representing 400 Bcf per year of gas production. (Section 8).

- Underground coal gasification (UCG) is a technology to convert energy in underground coal to gas. The available resource base for North America is in the thousands of Tcf. Large scale projects may have economics in the range of $5 to $6 per MMBtu. Costs could be much higher, depending on the need for water treatment or site mitigation. Here, too, greenhouse gas legislation could result in significant cost increases. (Section 8).

- About 150 Bcf per year of landfill methane was captured and used in 2004. Methane production (capture and use) potential from landfill operations is estimated at 800 Bcf per year by 2020. This is based on an average methane component of raw landfill gas of 50 percent.

- With regard to gas from oil shale thermal processes, biogas, and arctic and offshore gas hydrates, none of these is expected to have a major contribution through 2020, although significant technology gains have been made in recent years. Gas hydrates are the subject of a large federal and international research effort. (Section 8).

1.5 North American Natural Gas Production Forecast

Figure 1 summarizes the ICF Lower-48 natural gas production forecast, broken out into conventional and non-conventional categories. It illustrates the expected decline in natural gas production from conventional (high permeability) reservoirs. (Note that offshore shelf and deepwater production are included with conventional gas). Increasing annual production through 2020 is shown to be driven by both tight gas and shale gas. Tight gas remains the dominant category of unconventional gas through the forecast, despite a large increase in shale gas. Coalbed methane will grow only moderately during this timeframe. Both tight gas and shale gas production are expected to continue to increase beyond 2020. In 2007, unconventional natural gas production represented 48 percent of Lower-48 natural gas production. By 2020, it is forecast to be 69 percent of the Lower-48 total.

It should be noted that the forecast presented here assumes that the offshore moratoria that were in place through mid-2008 remain in effect. Thus, there is no production from new areas of the Atlantic or Pacific offshore or the off-limits part of the Eastern Gulf of Mexico.

Figure 1 Lower-48 Natural Gas Production Forecast

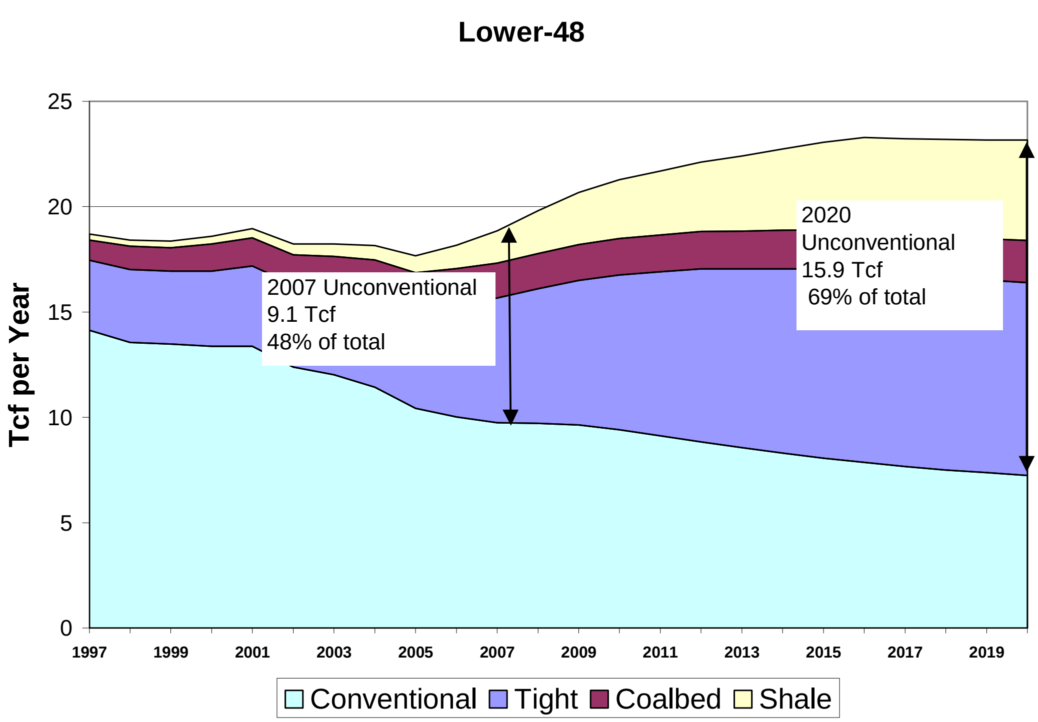


Figure 2 shows a comparison with the current (2008) EIA Annual Energy Outlook. The EIA forecast for Lower-48 natural gas production is much lower than ICF's forecast, and production peaks at only 19.3 Tcf per year in 2016. Unconventional gas production increases only slightly, peaking at 9.6 Tcf in 2018. EIA's forecast of conventional production (not shown) declines from 9.7 Tcf in 2007 to 7.9 Tcf in 2030, while the ICF forecast declines to 6.1 Tcf in 2030. While there are several factors that impact production forecasts, including price and technology improvement assumptions, the most significant reason ICF's unconventional gas forecast is higher is ICF's larger shale gas resource, as discussed in Section 5. Other factors including U.S. electricity and natural gas demand assumptions also account for some of the difference.

Figure 2 Comparison of Forecast to EIA 2008 Annual Energy Outlook

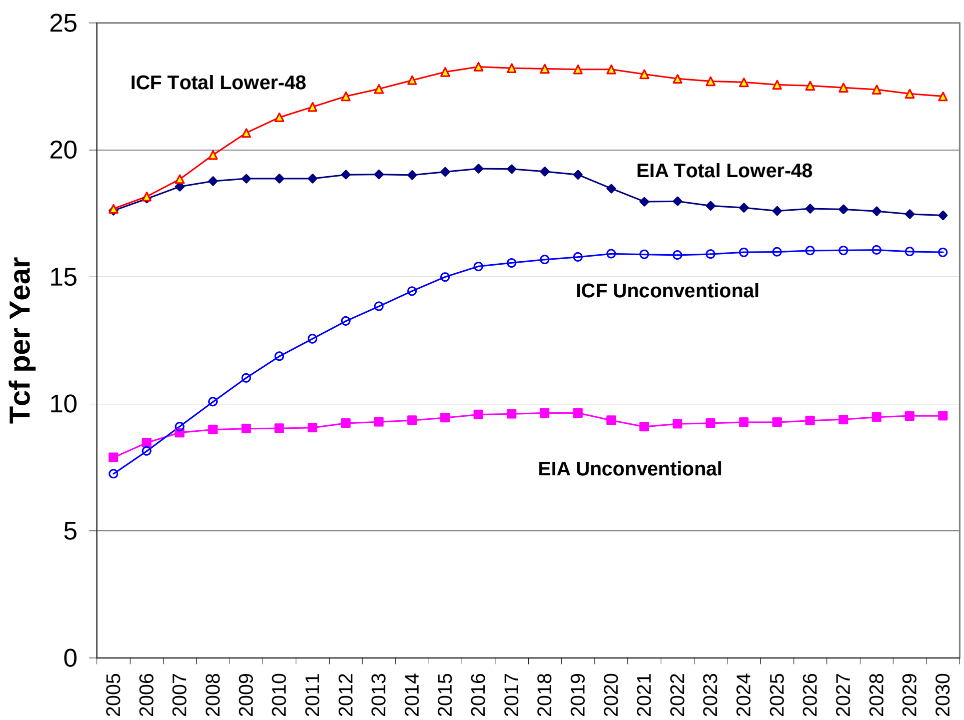
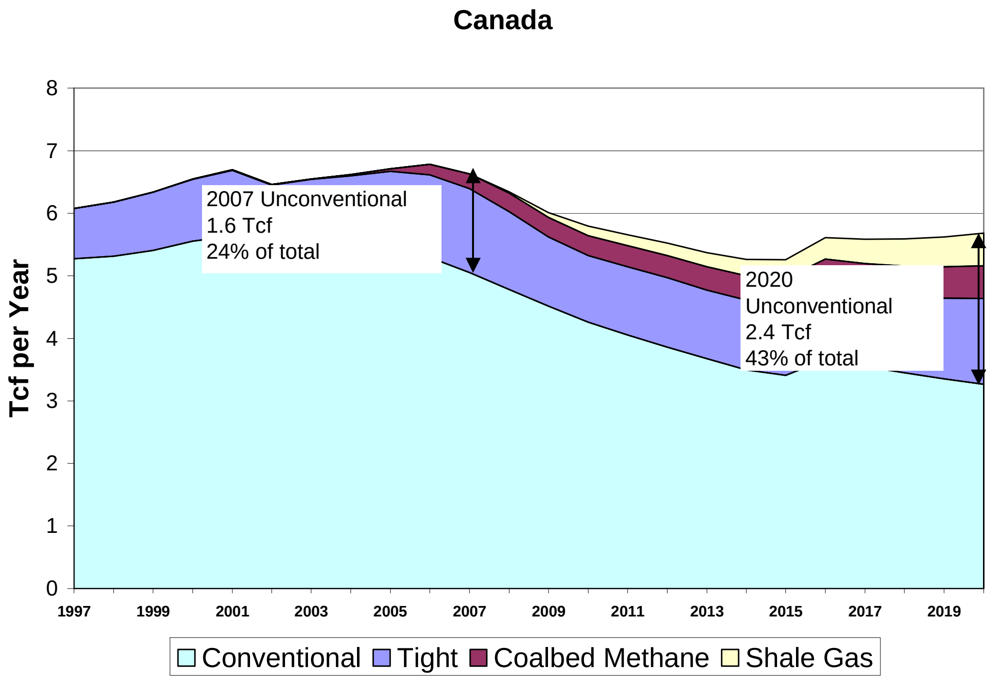


Figure 3 shows expected Canadian production. Conventional production is expected to decline overall through 2020. An exception to the conventional production decline is the assumed startup of the Mackenzie gas pipeline in 2016 (shown on the chart as an increase in that year). All categories of unconventional natural gas will grow, but not enough to offset the decline in conventional natural gas production. Canadian shale gas production is expected to be very significant, but it is difficult to forecast due to the emerging nature of the plays.

In 2007, unconventional natural gas production represented 24 percent of Canadian natural gas production. By 2020, it is forecast to be 43 percent of the total.

Figure 3 Canada Natural Gas Production Forecast



1.6 Report Findings by Category of Unconventional Gas

Table 1 summarizes the findings of this report. The table shows each of the categories of unconventional gas evaluated here. Where available, the table summarizes the recoverable or in-place natural gas resource base, the current rate of production, the forecasted 2020 rate of production, the estimated cost, and important considerations in assessing the resource category. The following is a summary of the findings for each category:

Table 1 Summary of Report Findings

Source	Estimated Resource Base	Estimated Production in 2007	Forecast Production in 2020	Estimated Cost per Unit	Major Obstacles and Uncertainties
Coalbed Methane	65 TCF (US) 33 TCF (Can) recoverable gas	1.8 TCF (US) 0.2 TCF (Can)	2.0 TCF (US) 0.5 TCF (Can)	Wide range of costs. 2007 average was about \$4.20 per MMBtu in US.	Land access and produced water disposal concerns have slowed development. Technology improvements take time to develop and to penetrate the market.
Gas Shales	385 TCF (US) 131 TCF (Can) recoverable gas	1.4 TCF (US) 0.0 TCF (Can)	4.8 TCF (US) 0.5 TCF (Can)	Wide range of costs. 2007 average was about \$5.00 per MMBtu in US.	Emerging areas have considerable geologic and geomechanical uncertainty. Technology improvements take time to develop and to penetrate the market. Water impacts, environmental concerns and lack of infrastructure will slow development, especially in areas with little historical oil and gas development.
Tight Gas	174 TCF (US) 66 TCF (Can) recoverable gas	5.8 TCF (US) 1.3 TCF (Can)	9.2 TCF (US) 1.4 TCF (Can)	Wide range of costs. 2007 average was about \$5.90 per MMBtu in US.	Number and size of new of "sweet spots" will affect long-run production trends. Technology improvements take time to develop and to penetrate the market. Restricted land access in Rockies will constrain development.
Gas from Oil Shales (Horizontal Drilling)	1.8 TCF (US) (Bakken) recoverable gas	0.04 TCF (US)	0.18 TCF (US)	Total hydrocarbon costs were about to \$31 per barrel oil equivalent (\$5.30/MMBtu) in mid-2008.	Gas gathering infrastructure is now catching up with associated gas production. Future production depends on oil prices and technology evolution.
Gas from Oil Shales (Thermal)	5+ TCF gas in place in US, but thermal production of the 750 billion barrels of rich shale (>25 gallons per ton) would produce 100's of TCF of gas.	none	Small amount associated with pilot or small commercial projects.	Total hydrocarbon rsource costs for rich shales might be \$28 to \$41 per barrel oil equivalent (about \$5 to \$7 per MMBtu).	Risk of immature technology, uncertain environmental impacts and regulatory régime. Significant cost increase is possible under GHG constraints. Much (and possibly all) of generated gas would be used to produce heat energy in shale oil production.
Aboveground Coal Gasification	Thousands of TCF	0.06 TCF Great Plains Plant	Nine plants are planned, and will produce more than 400 Bcf per year.	Significant economies of scale. Large-scale plants are in \$7.60 to \$9 per MMBtu range.	High costs of proven technology, risks of new technology, high initial costs and long cost recovery period. Significant cost increase is possible under GHG constraints.
Underground Coal Gasification	Thousands of TCF	none	Small amount associated with pilot or small commercial projects.	Significant economies of project scale and of coal-seam thickness. Large-scale projects might be in \$5.60 to \$6.30 per MMBtu range. Cost could be higher if significant investment in water treatment or site mitigation were needed.	Concerns about ground water contamination will need to be addressed. Risk of immature technology, high initial costs and long cost recovery period. Significant cost increase is possible under GHG constraints.
Landfill Gas	1,600 to 1,800 operating landfills in the U.S.	150 bcf methane (300 bcf raw landfill gas) used for energy in 2004	800 Bcf of methane is annual potential if all best sites are used for energy	Cost of capture of raw gas is about \$3 per MMBtu.	High energy prices and concerns about GHG emissions are likely to lead to more capture of LFG, but use as low-Btu onsite fuel may often be the most economic choice.
Biogas	0.8 TCF per year of methane is potential in US from all cattle. For Canada potential from cattle is 0.1 Tcf methane per year. Wastewater annual potential is 0.3 Tcf of methane for US and 0.03 Tcf for Canada.	Approximately 2 bcf per year at farms	10's of Bcf per year in US are likely. Legislated GHG limits would boost use further.	Digesters for dairy farms have costs of \$10.00 to \$26.00 per MMBtu on net basis (accounting for any fuel used to heat digester). For warmer climates, costs might be in \$6.50 to \$19.00 per MMBtu range.	High energy prices and concerns about air pollution, odors and GHG emissions are likely to lead to more capture of agricultural and water-treatment biogases. However, use as low-Btu onsite fuel may often be the most economic choice.
Gas Hydrates	303,000 TCF in place in U.S. with thousands of TCF in better reservoirs	none	Very little, if any	Hypothetical cost examples suggest that the best Arctic resources might be producible for \$2 to \$8 per MMBtu at the wellhead. Best deepwater GOM resources might have costs of \$13 to \$24 per MMBtu.	Considerable uncertainty exists about characteristics of resource and its producibility. Only a small portion of gas-in-place should be expected to be target for production. Arctic hydrates production to be limited by lack of gas pipeline transportation to markets.

Coalbed Methane

Coalbed methane production in the Lower-48 in 2007 was 1.7 Tcf, and in Western Canada was 0.2 Tcf. The largest volumes of Lower-48 coalbed methane are produced in the San Juan Basin in New Mexico and Colorado and the Powder River Basin in Wyoming. ICF forecasts that by 2020, U.S. coalbed methane production will be 2 Tcf per year and Canadian production will be 0.5 Tcf per year. Environmental issues including produced water quality and disposal and well density in the U.S. and Canada are likely to have impacts on future development. This resource is characterized by a wide range of resource costs, spanning a range of less than $1.00 per MMBtu to $7.00 or more, with an average in 2007 of $4.20 per MMBtu. (See Section 7 for a detailed discussion of our approach to estimating resource costs).

Gas Shales

With the tremendous success of the Barnett, Fayetteville, and Woodford Shales in the U.S., the gas shale resource base will play a major role in future natural gas production. Recent announcements of emerging plays in Appalachia, Northern Louisiana, British Columbia and South Texas indicate the widespread potential. The current ICF resource assessment is 385 Tcf of recoverable natural gas in the U.S. and 131 Tcf in Canada. Production in 2007 was 1.5 Tcf in the U.S., with no documented production in Canada. Our forecast is for approximately 4.8 Tcf of U.S. shale gas production by 2020, and 0.5 Tcf of Canadian shale gas production. The average resource cost in 2007 was about $5 per MMbtu. Emerging shales have considerable geologic variability and uncertainty. In addition, water use impacts, environmental concerns related to the number of wells, and infrastructure restrictions and requirements will all be significant factors, especially in areas with little historical oil and gas development.

Tight Gas

The tight gas resource base in both the U.S. and Canada is tremendous, and is currently assessed by ICF at 240 Tcf, of which 174 Tcf is the U.S.. Current U.S. production is 5.9 Tcf per year while Canadian production is estimated to be 1.3 Tcf per year. Most of the U.S. development is occurring in the Rockies and East Texas. ICF forecasts that tight gas will account for 9.2 Tcf of U.S. production and 1.4 Tcf of Canadian production by 2020. As with the coalbed methane resource, the ICF forecast accounts for some restricted access and the cost impact of environmental regulations. Tight gas has a wide range of costs, and the 2007 average cost was about $5.90 per MMBtu, with a range of about $3.00 to $15.00 per MMBtu.

Gas from Oil Shales (Horizontal Drilling)

In addition to gas shale deposits, oil shale deposits containing associated natural gas are now being developed in the U.S. This type of oil shale is categorized here as "horizontal drilling" oil shale to differentiate it from the more unconventional oil shale such as that in western Colorado that requires heating to recover the oil. In the Williston Basin of North Dakota and Montana, operators are using horizontal drilling to tap the Bakken Oil Shale. This play was assessed earlier this year by the U.S. Geological Survey (USGS) at 3.65 billion barrels of oil and 1.85 Tcf of associated gas. A similar play is underway in the oil leg of the Barnett Shale. Resource costs for gas from oil shale using horizontal drilling are approximately $31 per barrel of oil equivalent or $5.30 per MMBtu.

Gas from Oil Shales (Thermal Methods)

Most of the worldwide oil shale resource is found in the U.S. The U.S. in-place oil shale resource is approximately 2 trillion barrels.[1] Of this amount, approximately 1.5 trillion barrels (with a richness of greater than 10 gallons per ton of shale) is in the Green River formation of Colorado, Utah, and Wyoming, and about 200 billion barrels is in the Eastern U.S. in the Appalachian Devonian Shale.

Thermal production of the 750 billion barrels of rich shale deposits would produce hundreds of Tcf of gas. Resource costs for rich shales are estimated to be in the range of $28 to $41 per barrel of oil equivalent or about $5 to $7 per MMBtu. However, much if not all of the gas produced may be used to produce heat for thermal conversion. Significant environmental and regulatory hurdles would need to be overcome to develop this resource.

Aboveground Coal Gasification

Gasification systems convert coal or other solid or liquid feedstocks such as petroleum coke or heavy oils into a gaseous synthetic fuel. The most widely used type of gasifier is the steam-oxygen type that produces a synthetic gas which is composed predominately of hydrogen (H2) and carbon monoxide (CO). The only commercial coal gasification plant of this kind making methane in the U.S. is of this type. It is the Dakota Gasification Plant in Beulah North Dakota, which uses a steam-oxygen gasifier.

The conversion of short tons of coal to methane is calculated on an energy basis. Assuming 10,000 Btu/lb of coal as mined at 60% thermal conversion efficiency, about 12,000 standard cubic feet of methane is produced from each short ton of bituminous coal.

The available resource base for North America is in the thousands of Tcf. Large scale plants would have the most favorable economics, generally in a range of $7.60 to $9 per MMBtu. Nine planned plants with a total output of over 400 billion cubic feet (Bcf) per year are identified in this report. Significant environmental issues include coal mining issues related to surface disturbance, water issues, and greenhouse gas emissions. Greenhouse gas legislation could result in significant cost increases.

Underground Coal Gasification

Underground coal gasification is a technology to convert energy in underground coal to a combustible gas that can be used for power generation and as a feedstock for refined fuels and chemicals. The process involves drilling air or oxygen injection wells and gas production wells. The coal seam reacts with oxygen or air to produce a relatively low quality, combustible gas. The raw gas stream contains methane, carbon monoxide, hydrogen, and carbon dioxide, along with other components. The UCG process is halted when injection of air or oxygen ceases.

The available resource base for North America is in the thousands of Tcf. Large scale projects are expected to have the best economics, generally in the range of $5.60 to $6.30 per MMBtu. Costs could be much higher, depending on the need for stricter water treatment or site mitigation. Greenhouse gas legislation could result in significant cost increases.

Landfill Gas

[1] Southern States Energy Board, 2006, "American Energy Security," July, 2006.

Landfill gas is generated by the decomposition of organic waste in anaerobic (oxygen-deprived) conditions at municipal solid waste disposal facilities. Of all the manmade sources of methane emissions in the U.S., landfills account for the most generation from a single source category—25 percent of the total in 2004. Besides the composition of the waste itself, the amount of methane generated by a landfill over its lifetime is dependent upon the quantity and moisture content of the waste as well as the design and management practices of the facility.

Over 800 Bcf of landfill methane will be generated in U.S. landfills by 2020. About 150 Bcf of landfill methane was used for energy in 2004. Cost of capture of the raw gas is about $3 per MMBtu. Use of this energy as a low-Btu on-site fuel to generate electricity may be the best economic choice in most cases.

Biogas

Agricultural biogas is the generation of methane through the anaerobic digestion of agricultural byproducts. There is growing interest in biogas for several reasons. First, farm operators already need to dispose of manure and anaerobic digestion is one method addressing disposal. Second, combustion of biogas is a way of reducing emissions of methane, a potent greenhouse gas. Third, biogas is classified as a renewable fuel, and can be used to meet renewable mandates. In the past, the focus has been on using biogas for on-site power generation. More recently, developers are starting to clean up the gas and supply it to end-use customers via gas pipelines.

Potential biogas methane production from U.S. cattle is 800 Bcf per year and from Canada the potential is 100 Bcf per year. Wastewater biogas has the potential to produce 300 Bcf per year of gas in the U.S. and 30 Bcf in Canada. By 2020, it is likely North America will see the use of only a small fraction of this resource, estimated to be tens of Bcf per year of gas production. Biogas digesters for dairy farms have costs in the range of $6.50 per MMBtu (low end for warm climates, where little or no heating of the digesters is needed) to $26 per MMBtu.

Gas Hydrates

Methane hydrates are ice-like solids in which methane molecules are trapped in water molecules in a cage-like structure called a clathrate. They are found in deepwater and arctic settings. The total assessed in-place potential for gas hydrates worldwide is approximately 700,000 Tcf with a wide range of uncertainty. (Note that in-place resources represent the total amount of methane present and are much larger than recoverable resources). The U.S. assessed in-place resource is about 300,000 Tcf. Of that amount, about 21,000 Tcf is in the Gulf of Mexico. There is no current estimate of potential technical or economic recovery and there is no commercial production worldwide. Due to the early stage of research, very little if any commercial natural gas hydrate production is expected by 2020.

ICF has developed several hypothetical cost scenarios to estimate the resource costs for hydrates. The best arctic resources may be economic at $2 to $5 per MMBtu at the wellhead, while the best deepwater resources may be economic in the range of $11 to $19 per MMBtu. Arctic hydrate development will be limited or non-existent until there is a natural gas pipeline to transport the gas to market.

1.7 Conclusions

Higher natural gas prices and technological advances have led to increasing unconventional gas production in the U.S. and Canada. The resource base and economic analyses presented in this report suggest that this trend will continue in the future, and that by 2020, 69 percent of U.S. gas production and 43 percent of Canadian gas production will be from unconventional sources. Approximately 300,000 unconventional gas wells will have to be drilled to achieve the gas production forecast. This represents an outlay of $560 billion for unconventional drilling and completion and other capital costs.

In addition to tight gas, coalbed methane, and shale gas, there are several other forms of potential unconventional gas production. Aboveground coal gasification and landfill gas collection are expected to contribute significantly by 2020, while other forms of unconventional gas will likely experience commercial production on a small scale.

The resource base of natural gas hydrates is tremendous, although no commercial production has been established. Research continues in the area of arctic and deepwater hydrates.

Potential impediments to the production forecast shown here include land access, water use and disposal, and well permitting delays. While such factors have been accounted for in the model and resource cost estimates, it is nevertheless difficult to quantify their impact.

The 2008 credit crisis and oil and natural gas price declines may lead to reductions in drilling programs planned by producers. However, the long-term need for energy in the U.S. and Canada should be strong enough to support the future levels of gas production presented here, albeit on a possibly slower pace.

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2 INTRODUCTION

Developments in horizontal drilling, hydraulic fracturing, and the emergence of numerous shale gas and tight gas plays have dramatically changed the nature of North American natural gas production potential over the past decade. In contrast to recent years of relatively unchanged production, U.S. natural gas production is now increasing, primarily as a result of onshore unconventional natural gas. Expansion of unconventional natural gas production has already had a large impact on the natural gas transportation and processing sectors of the industry. Examples include the expansion in recent years of gas pipeline systems carrying gas production from the Barnett Shale in the Fort Worth Basin, the Bossier tight sand in East Texas, and the tight gas and coalbed methane basins of the Rockies. Should production from shale gas and tight gas achieve the potential forecast here, additional large pipeline capacity additions will be required in coming decades.

Long-Term History of Gas Development in the U.S.

Through most of its history, the U.S. oil and natural gas industry focused on developing resources in high permeability rocks in well-defined traps. These “conventional” fields were characterized by the presence of contacts between natural gas, oil, and water. In the early decades, surface geology was often used to locate fields. Later, advances in geophysical techniques including gravity and seismic data, as well as advances in well logging and other technologies, were used to locate fields.

In recent decades, widespread use of high resolution two-dimensional (2D) as well as three-dimentional (3D) seismic allowed continued success in conventional plays and provinces such as the Gulf Coast. However, through time and with the completion of thousands of natural gas wells, it became apparent that, with the exception of new provinces such as the deepwater Gulf of Mexico and the ultra-deep shelf, most conventional U.S. plays were becoming relatively mature, as new discoveries were becoming smaller.

In parallel with this long-term emphasis on conventional exploration and production, the U.S. has a very long history of unconventional gas production. North America has vast deposits of in-place unconventional natural gas resources in the form of tight gas, coalbed methane, and shale gas.

Shale gas production in the U.S. dates to the 1800s with the early development of the Appalachian Devonian Shale in West Virginia, Kentucky, Pennsylvania and New York. This eventually involved the drilling of thousands of shallow low productivity vertical wells whose production in many cases was unrecorded. The wells were often stimulated with explosives. The lack of a significant pipeline system meant that the natural gas was used locally.   Appalachian shale gas production from these low volume wells continues to the present day.

The 1980s saw the development of the Michigan Basin Antrim Shale. This was also the time of the initial development of the Barnett Shale in the Fort Worth Basin of North Texas – a play that was to expand into, by most definitions, the largest and most prolific natural gas play in U.S. history.

Tight gas production in the U.S. dates to the 1940s with the development of the San Juan Basin in northwestern New Mexico and southwestern Colorado. Tight gas reservoirs were also developed starting in the 1950s and 1960s in Appalachia.

Coalbed methane production in the U.S. began in a significant way in the 1980s with the Fruitland coalbeds of the San Juan Basin in New Mexico and Colorado. Coalbed methane production in the San Juan increased rapidly in subsequent years, reaching 2 Bcf per day (Bcfd) by 1995. The Alabama Warrior Basin coalbed methane production also started in the 1980s and saw more modest growth to about 300 million cubic feet per day (MMcfd). Then came the development of the Powder River Basin in eastern Wyoming. Production from that play started in the mid-1990s and achieved one Bcfd by 2003. Coalbed methane production also started in Alberta several years ago and production now exceeds 650 MMcfd.

More Recent Developments

Gas resources may be viewed as a "resource pyramid." The concept of the "resource pyramid" is that the majority of natural resources are contained in low concentrations or poor rock quality. The apex of the pyramid is the low cost, high quality deposits that are generally produced first. In general, it was these higher quality portions of the resource pyramid that were developed in the early history of the industry. To obtain production from low quality rock, it is necessary to have improved technology and sufficient wellhead revenue to develop the resources economically.

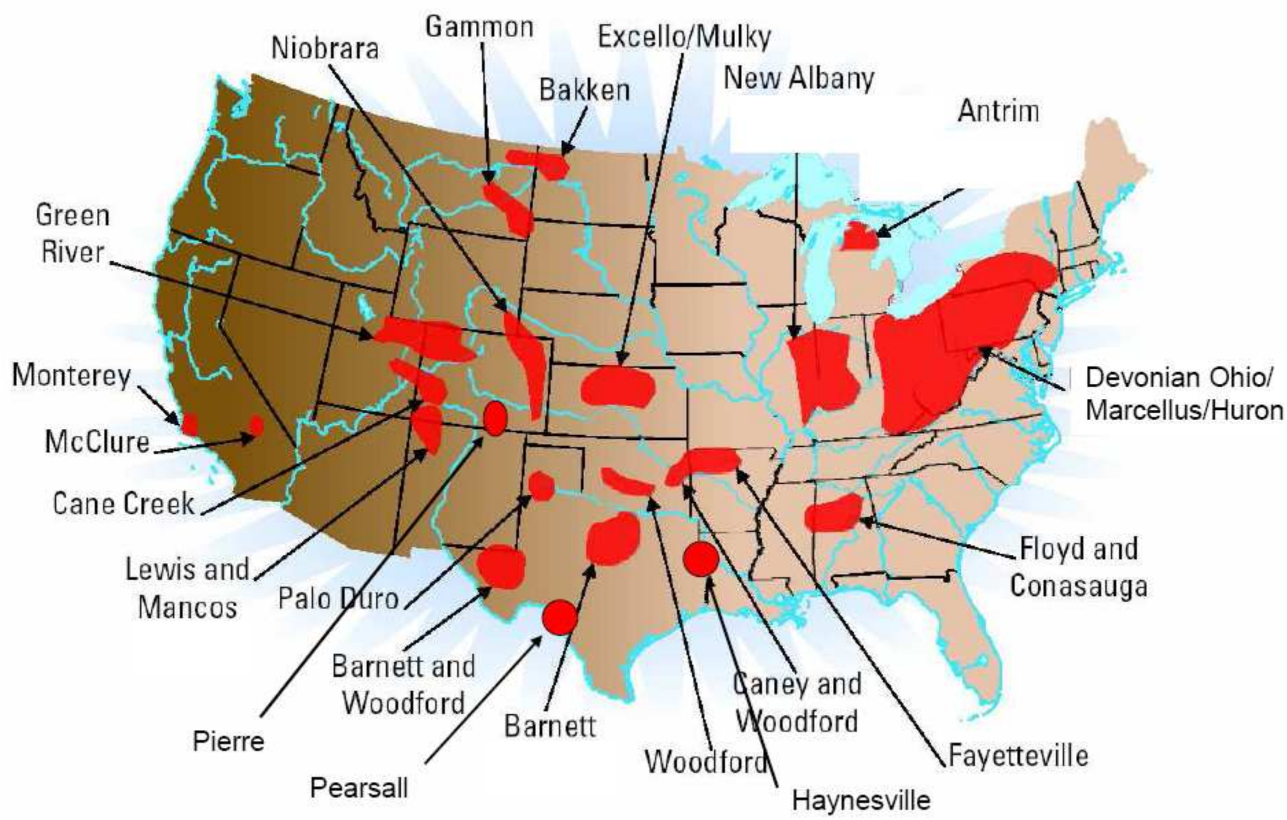
The keys to unlocking this gas include horizontal and directional drilling and advanced multi-stage fracturing technology. Advanced seismic data are also critical in many plays, especially those with more complex geology. Key areas of recent unconventional production growth in the U.S. include the Rockies tight gas and coalbed methane, East Texas tight gas, and North Texas and the Mid-Continent shale gas.

North America currently has three large-scale, active shale gas plays where production is rapidly increasing. These are the Barnett Shale of North Texas, and the Fayetteville Shale and Woodford Shale of Arkansas and eastern Oklahoma. Natural gas production from the Barnett Shale in Texas has grown very rapidly, with a year-end 2007 rate of 2.9 Bcfd and a current rate of approximately 3.5 Bcfd. It is expected that production from this play will continue to increase to a level of 5 Bcfd or more, representing 8 to10 percent of U.S. natural gas production by 2020.

The year 2008 has been a landmark year for the emergence of North American shale gas plays. Producers have announced major new horizontal drilling plays in the Marcellus and Huron Shales in the Appalachian Basin, the Utica Shale in eastern Canada, the Haynesville Shale in Louisiana and East Texas, and the Montney and Muskwa Shales in British Columbia. The location of current and emerging U.S. Lower-48 shale plays is shown in **Figure 4**.

Figure 4 Shale Gas Basins of the Lower-48.

Source: Modified from Schlumberger presentation, 2005 [2]



[2] Schlumberger, 2005, "Shale Gas," company white paper http://www.slb.com/media/services/solutions/reservoir/shale_gas.pdf

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3 DATA SOURCES

The following sources of information were used to prepare this report:

Production and Drilling Data

The Lasser commercial well level gas production database was the main source of gas well production information. ICF processing of the data allows analysis of coalbed methane, tight gas, and shale gas production by basin and formation. The database has also been processed to determine the number of annual producing wells by basin and play. Production and drilling activity data were also obtained from state websites and company presentations.

Over the past fifteen years, ICF has developed and maintained databases of unconventional natural gas production in the U.S. Much of the original work was done during the 1990s for the Gas Research Institute. [3] The current study expands upon that work to identify unconventional natural gas wells and production through 2007.

Company Activity Data

Information on the individual producing firms comes primarily from 2008 investor presentations. This was augmented with various industry trade publication articles.

Resource Assessments

Several government and industry sponsored organizations publish resource assessments. In the U.S. the U.S. Geological Survey (USGS) has an active, ongoing assessment effort that includes the major forms of unconventional natural gas. [4] They have also assessed resources such as methane hydrates. The Minerals Management Service (MMS) periodically assesses the conventional offshore resources of the U.S. They recently completed a preliminary assessment of the natural gas hydrate potential in the deepwater Gulf of Mexico, and those results, as well as the hydrate assessment of the USGS, are presented.

Other U.S. groups carrying out resource work include the Department of Energy, the Potential Gas Committee, and industry organizations including the National Petroleum Council. In 2008, a

[3] Gas Research Institute, 1999, "Unconventional Gas Field, Reservoir, and Completion Analysis of the Continental United States," Gas Technology Institute (formerly GRI), Chicago, IL , Report GRI 98/0364.1.
[4] USGS, 2008, National Oil and gas Assessment, http://energy.cr.usgs.gov/oilgas/noga/

report was published by the American Clean Skies Foundation, which assessed the potential for shale gas production in the U.S. [5]

In Canada, resource assessments are published by the National Energy Board, provincial energy agencies, and the Canadian Gas Potential Committee. Other Canadian organizations include the Canadian Association of Petroleum Producers and the Canadian Society for Unconventional Gas. Specific report references are provided with the tables in Section 5 of this report.

ICF has carried out volumetric resource studies on several of the most active shale gas plays in the U.S. These include estimates of total gas-in-place, drilling depth, spacing, and recovery per well.

Well Recovery and Resource Costs

A data processing method was applied to the Lasser well level production data to estimate recovery per well for the major unconventional plays. ICF evaluated the production history by well "vintage" or year of completion. Each vintage of wells was evaluated using statistical methods to evaluate the production rate decline through time. This information was extrapolated to estimate future production from each vintage. The past production plus the estimated future production equals the estimated ultimate recovery for that vintage of wells.

In addition, the major producers of shale gas, tight gas, and coalbed methane have published information on typical well recoveries and economics. The published data were compared to the statistical information to determine the best well recovery to use in the economic analysis.

After estimating ultimate recovery per well, the ICF Play Level Cost Model (PLCM) was used to evaluate the development economics of approximately 400 plays. This model estimates finding and development costs and uses a discounted cash flow approach to determine resource costs (minimum acceptable selling price at the wellhead) for each play.

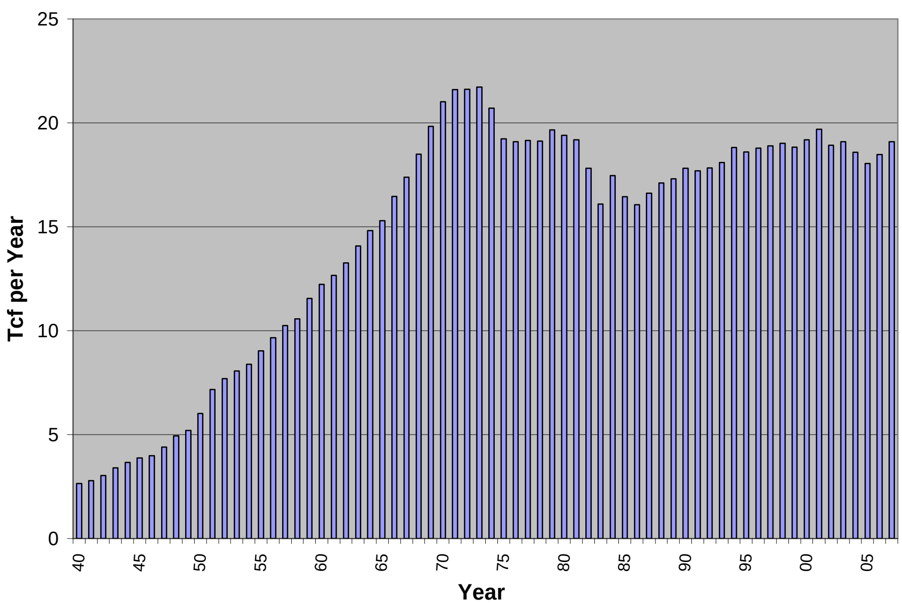
[5] American Clean Skies Foundation, 2008, http://www.cleanskies.org/

4 NORTH AMERICAN NATURAL GAS PRODUCTION, RESERVES, AND DRILLING ACTIVITY

4.1 Natural Gas Production Trends

Since 1940, the U.S. has produced approximately 1,050 Tcf of natural gas. [6] **Figure 5** shows that natural gas production increased rapidly from the 1940s through the 1960s and peaked in 1973 at almost 22 Tcf. Production then fell pretty steadily until bottoming in 1986 at 16 Tcf. This was followed by a period of moderate production growth and then a flattening of production over the past decade. The 2007 production rate was approximately 19.2 Tcf, a significant increase over the rate of 18.5 Tcf in 2006.

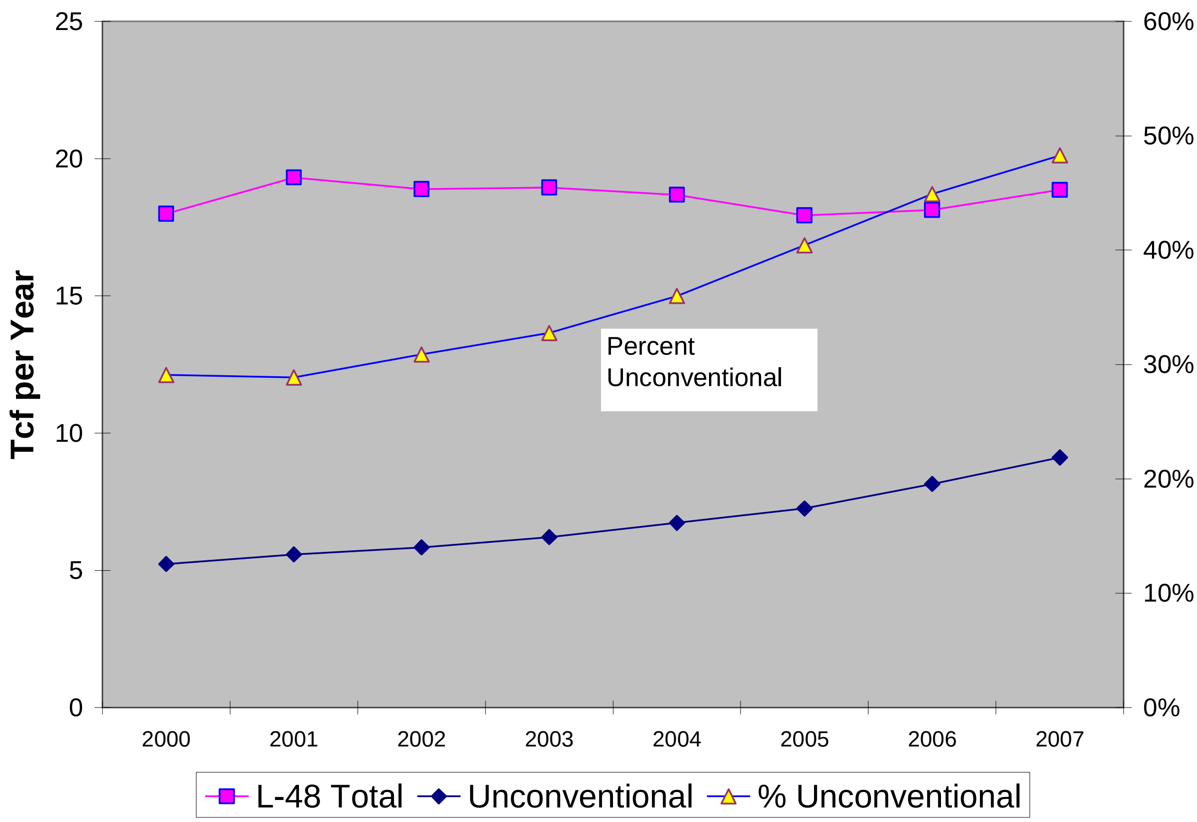
Figure 5 U.S. Dry Natural Gas Production 1940 - 2007



[6] This figure is estimated based upon analysis originally done for the 2003 National Petroleum Council North American gas study, with the addition of recent years of production. Various published sources including reports from the American Petroleum Institute were used for production data older than 1979 when the Department of Energy began reporting U.S. production.

Figure 6 shows recent U.S. natural gas production trends on a wet, marketed basis (as opposed to dry gas production, which excludes gas plant liquids and is slightly lower). Production has declined slightly since 2000, but has increased since 2005. The chart displays total unconventional natural gas production (coalbed, shale, and tight) and the percentage of production that is unconventional. In 2007, about 9.1 Tcf or 48 percent of U.S. marketed production is characterized as unconventional using our database. (Note that while coalbed methane production is generally tracked by the states and reported to DOE, tight gas and shale gas are not yet broken out by operators and reported to DOE so their volumes are based upon the approaches and data sources described in this report.)

Figure 6 Lower-48 Marketed Natural Gas Production and Unconventional Percentage



4.2 Production by Resource Type

In 2007, Lower-48 unconventional gas production was 9.1 Tcf per year. This consisted of 5.9 Tcf of tight gas, 1.7 Tcf of coalbed methane, and 1.5 Tcf of shale gas. Canadian unconventional gas production was 1.58 Tcf, and consisted of 1.34 Tcf of tight gas and 0.24 Tcf of coalbed methane. There was no reported shale gas production in Canada.

Figure 7 shows the growth in unconventional production that has occurred since 1970. During the indicated period, tight gas constituted the majority of growth in unconventional gas. Coalbed methane experienced a period of growth in the 1980s and 1990s but has generally flattened since then. Shale gas production was relatively constant for decades until the advent of recent plays such as the Barnett Shale in the Fort Worth Basin.

Figure 7 Lower-48 Unconventional Natural Gas Production Since 1970

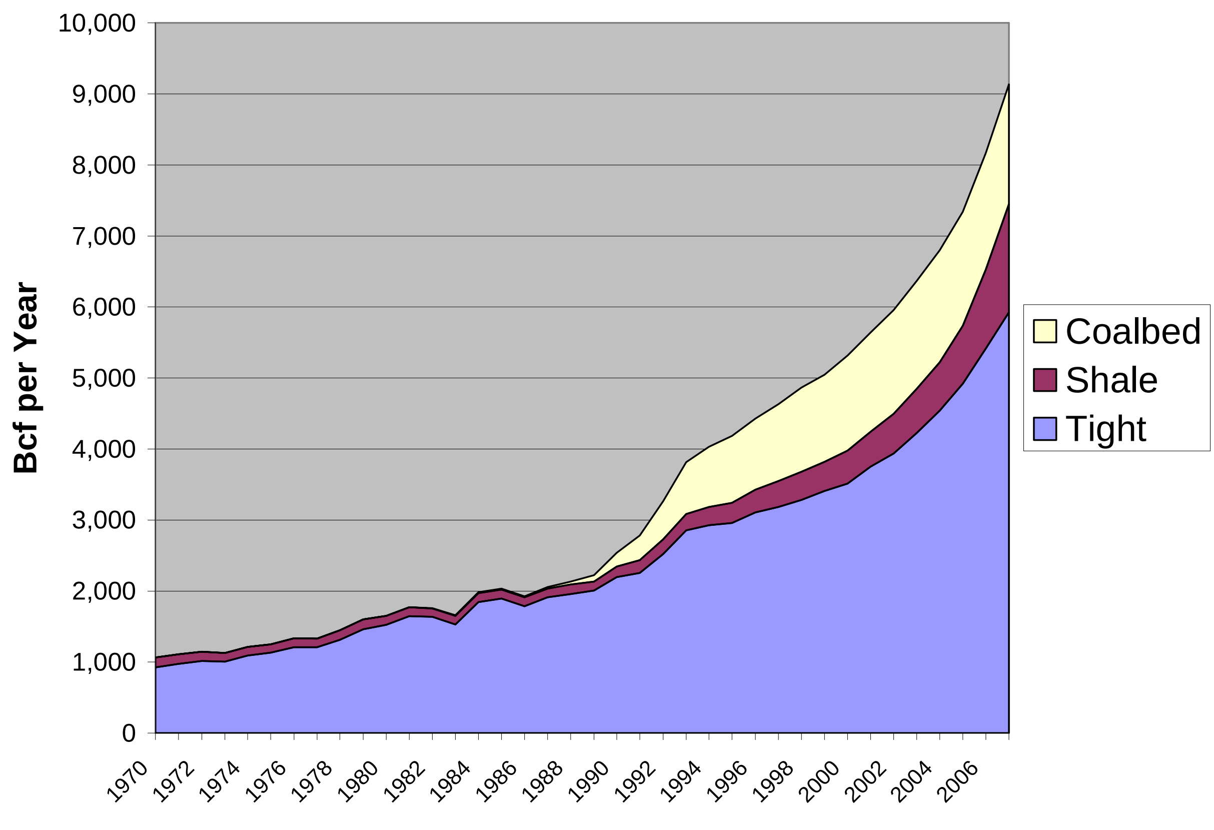


Figure 8 is a detail of tight gas production by area. The chart illustrates the dramatic growth in the Rockies and East Texas in recent years. Prior to this period, there was a significant increase in tight production in the Texas portion of the Gulf Coast. The early years of tight gas production were dominated by the San Juan Basin.

Figure 8 Lower-48 Tight Gas Production by Region

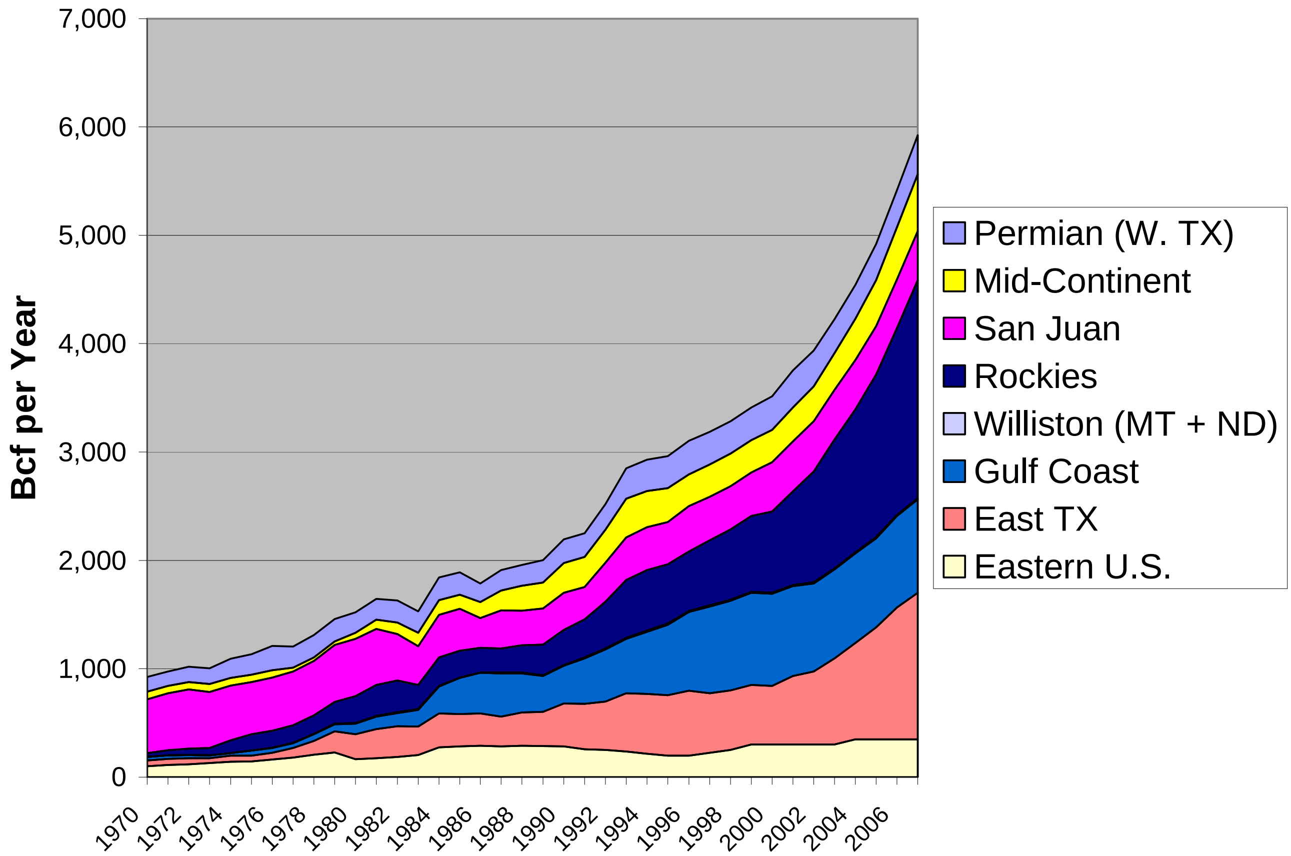


Figure 9 shows the trends in shale gas production by region. The Devonian Shale of the Appalachian Basin has produced at about 100 Bcf per year in recent decades. The production is estimated because of lack of detailed reporting in the region. The Antrim and New Albany shales in the Michigan and Illinois Basins, respectively, experienced a surge in activity in the 1990s. The recent dramatic growth of the Barnett Shale in North Texas is illustrated. Most of the growth in the Barnett and the Lower-48 as a whole has been since 2000. On the scale of this chart, the production from the Fayetteville and Woodford shales in the Mid-Continent is shown to be emerging in the last few years.

Figure 9 Lower-48 Shale Gas Production by Region

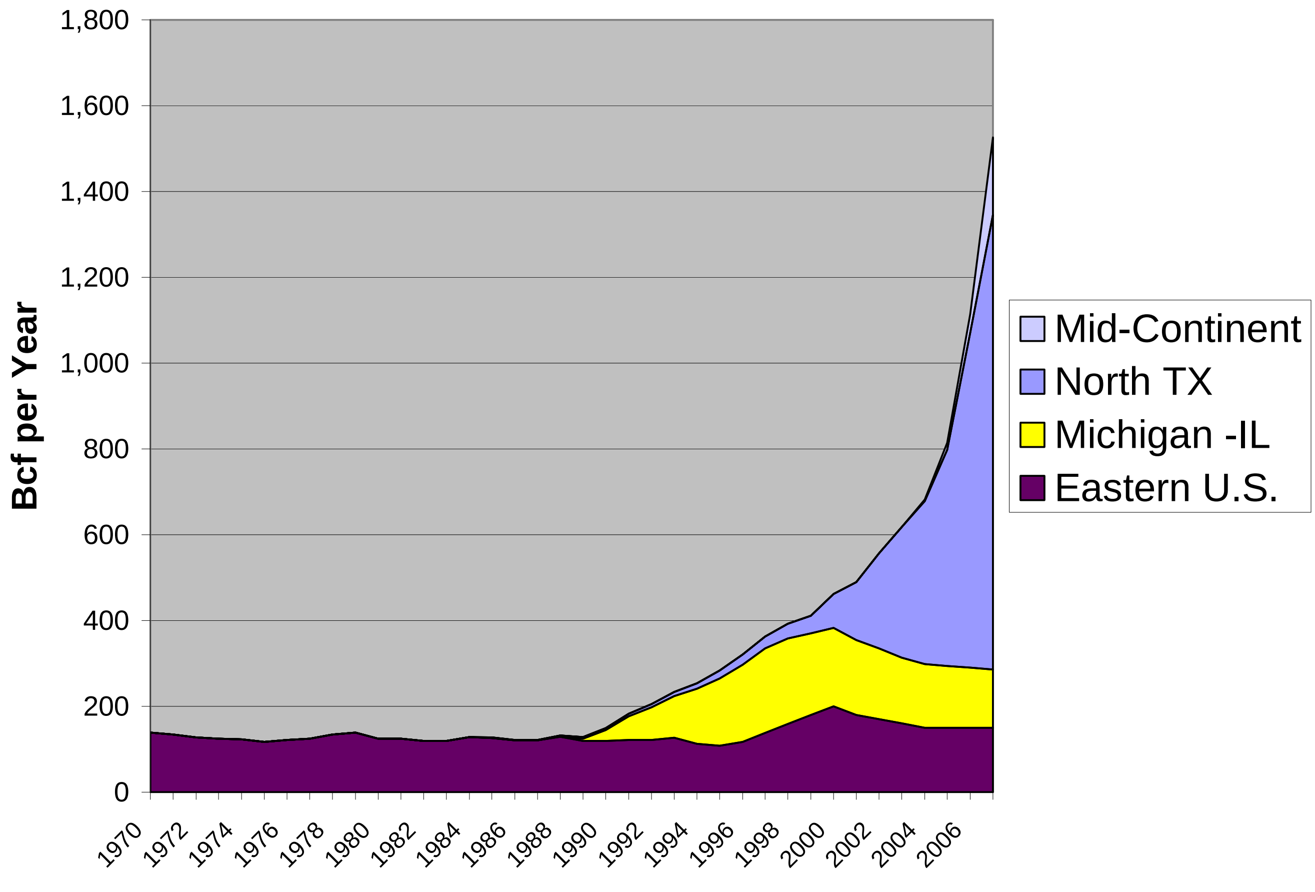
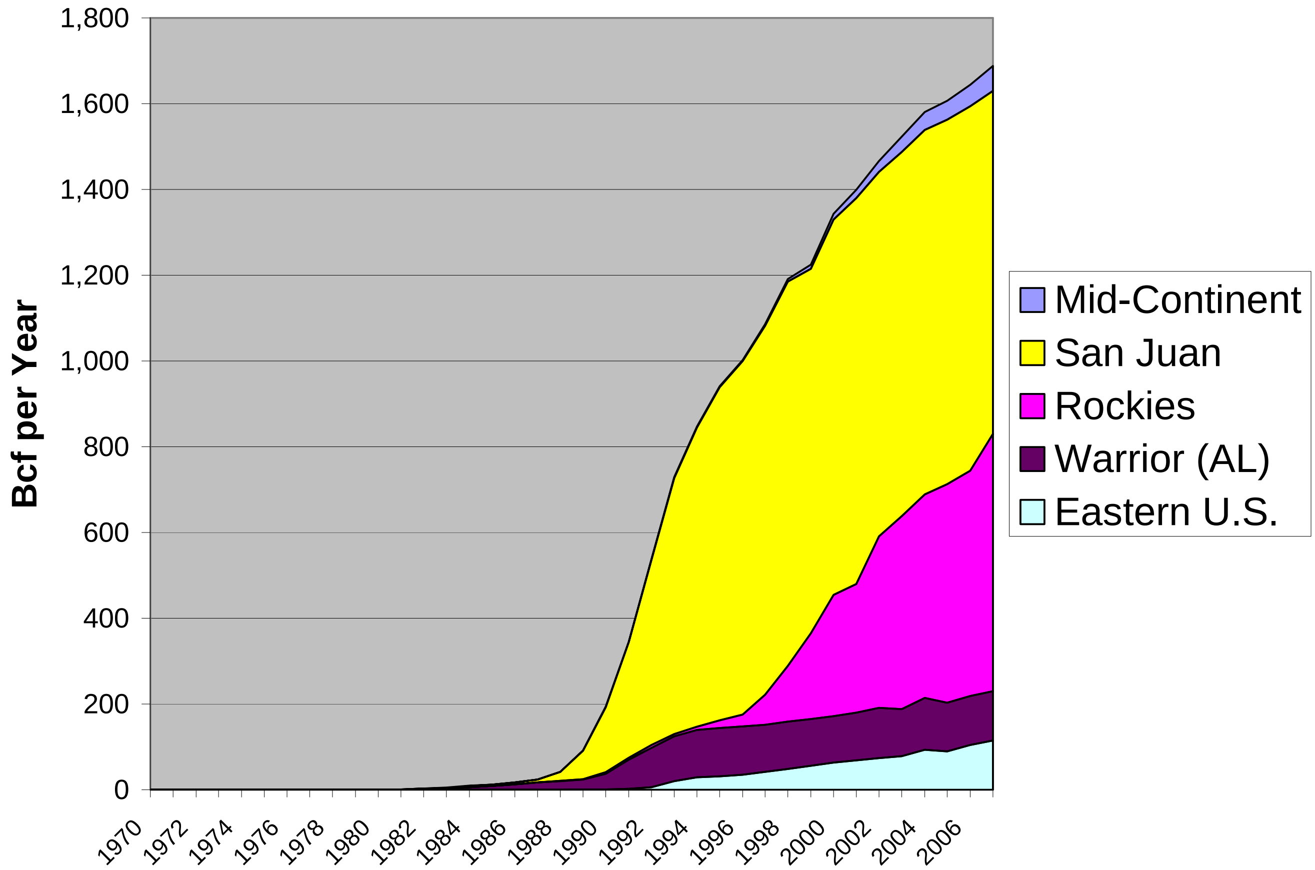


Figure 10 shows the trends in coalbed methane production by region. Initial coalbed methane production was from the San Juan Basin in northwestern New Mexico and southwestern Colorado, as well as the Warrior Basin in Alabama. San Juan Fruitland coalbed methane surged to over 900 Bcf per year. Powder River Basin coalbed methane production grew rapidly in the 1990s to achieve a current production rate of over 400 Bcf per year. Significant Rockies coalbed production is found in the Uinta Basin of Utah.

Figure 10 Lower-48 Coalbed Gas Production by Region



4.3 Natural Gas Reserves and Reserve Additions

U.S. natural dry gas production (gas production after the removal of impurities and natural gas plant liquids) has been almost constant since 2000, as shown in **Table 2**. Proved reserves show a different trend, with a 27% increase since 2002. *Proved reserves* are defined by the Energy Information Administration as:

> "The estimated quantities of natural gas which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." [7]

Annual natural gas reserve additions have increased substantially. *Reserve additions* are defined by EIA as:

> "Adjustments, net revisions, extensions to old reservoirs, new reservoir discoveries in old fields, and new field discoveries."

The great majority of these new reserves are in unconventional gas formations. Typically, unconventional gas wells have higher "reserve to production ratios" meaning that they will produce for many years. This is reflected in the national trend of increasing gas reserve additions and year-end reserves. Although not shown on the table, there has also been an increase in the "non-producing" portion of proved reserves. (Most reserves are "producing" reserves, but some reserves are "non-producing.") This trend also results from more drilling in unconventional reservoirs, because of the nature of development of those resources.

Table 2 U.S. Lower-48 Dry Natural Gas Production and Reserves

Trillion Cubic Feet
EIA Form-23 Reports

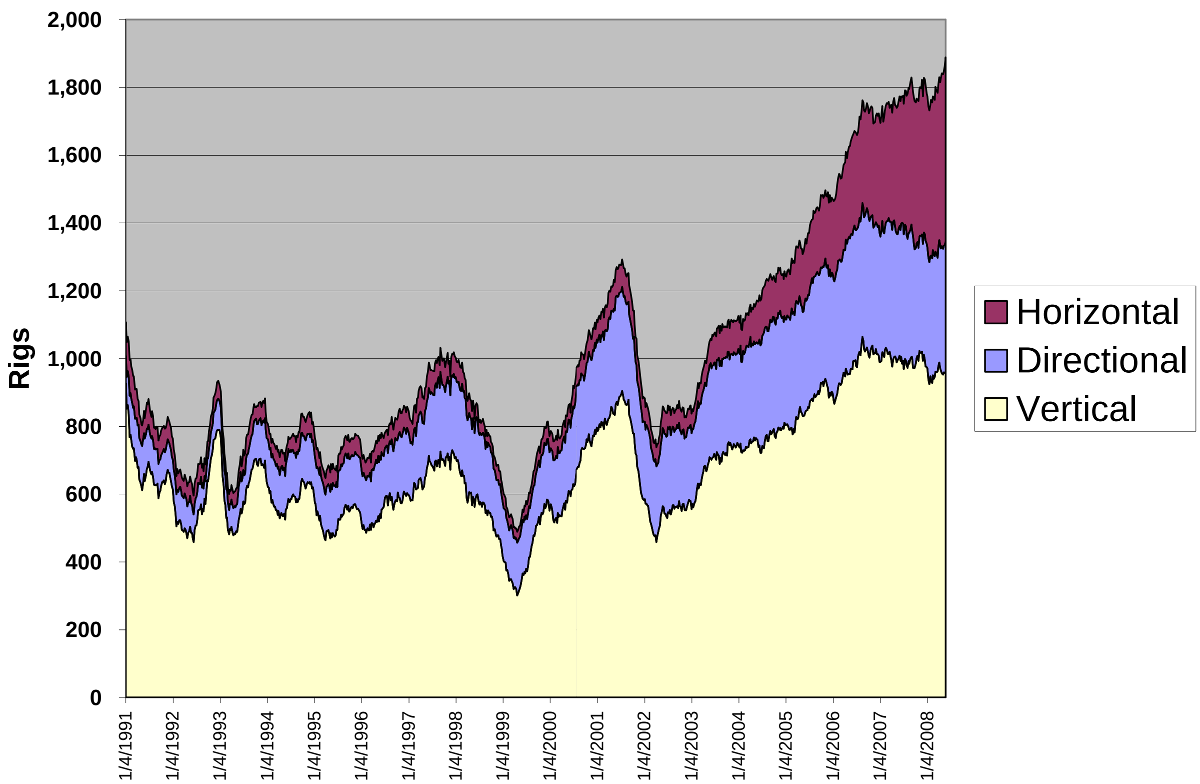
Year	Starting Proved Reserves	Production	Net Reserve Additions	Ending Proved Reserves
2000	158	18.7	28.7	168
2001	168	19.3	26.3	175
2002	175	18.9	21.9	178
2003	178	18.9	21.9	181
2004	181	18.7	21.7	184
2005	184	18.0	30.0	196
2006	196	18.1	23.1	201
2007	201	19.1	44.1	226

[7] U.S. Energy Information Administration, 2008, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves – 2007 Annual Report," October, 2008.

4.4 Drilling Activity – U.S. and Canada

There have been some very significant trends in North American drilling activity, most of which reflect the increased emphasis on unconventional natural gas. **Figure 11** shows the trends in U.S. active drilling rigs, as reported by Baker Hughes. [8] The chart displays total oil and gas drilling activity broken out by the number of drilling rigs utilizing "vertical," "directional," or "horizontal" drilling techniques. (No detailed data are provided by Baker-Hughes for just gas drilling). The 1990s saw relatively low rig activity levels, and this period was dominated by vertical drilling. Starting about 2000, the drilling activity picked up, again dominated by vertical drilling. In recent years, overall drilling has increased greatly, largely as a result of horizontal and directional drilling techniques. The increased horizontal drilling is associated primarily with shale gas activity.

Figure 11 U.S. Drilling Activity by Type



[8] Baker Hughes, 2008, http://www.bakerhughesdirect.com

Table 3 presents a summary of gas completion activity and the role of unconventional natural gas completions in the U.S.   Gas completion statistics record the number of wells completed as gas wells. (Note that this data is derived from counts of new producing wells, which is not identical to annual natural gas completions by completion date). The bottom portion of the table shows that unconventional drilling in 2007 represented 25,000 out of 31,000 gas wells drilled. The most active plays include the Barnett Shale, the East Texas Bossier, and the Powder River Basin.

Table 3 Unconventional Well Completion Activity in the U.S.

(Play totals based on new producing well counts; Not identical to completed wells; includes estimates.)

Shale Plays

	Ft. Worth Barnett	Arkoma Fayetteville	Arkoma Woodford	Michigan Antrim	Total in Other Plays	U.S. Shale Total
2004	815	13	38	302	1,060	2,228
2005	1,001	48	62	441	1,272	2,824
2006	1,393	116	126	452	1,147	3,234
2007	1,285	432	208	335	1,279	3,539

Tight Plays

	Green River Jonah-Pinedale	Piceance Mesaverde	Uinta Natural Buttes	San Juan Dakota/ Mesaverde	E. Texas Bossier/ Cot.Valley	Denver Wattenberg	Texas Dist. 4 Wilcox	Total in Other Plays	U.S. Tight Total
2004	245	433	234	605	1,146	219	162	8,628	11,672
2005	205	550	297	750	1,347	726	249	10,738	14,862
2006	250	600	360	800	1,491	556	308	12,609	16,974
2007	300	650	347	800	1,177	442	366	12,386	16,468

Coalbed Methane Plays

	Powder River	Uinta	San Juan	Raton	Total in Other Plays	U.S. Coalbed Total
2004	1,826	75	330	300	2,054	4,585
2005	1,750	80	400	350	2,201	4,781
2006	1,900	90	450	450	2,069	4,959
2007	1,700	100	450	450	2,438	5,138

U.S. Totals and Unconventional Component

	U.S. Total Gas Wells	U.S. Unconventional Gas Wells	U.S. Conventional Gas Wells
2004	24,400	18,485	5,915
2005	27,600	22,467	5,133
2006	30,600	25,167	5,433
2007	30,600	25,145	5,455

Table 4 presents the activity in the Western Canadian Sedimentary Basin. These data are from the Canadian Association of Oilwell Drilling Contractors. [9] Since there is no provincial tracking of tight gas in Canada, the unconventional counts shown are for coalbed methane only. The coalbed drilling alone accounts for about 25% of WCSB drilling. If one were to include the shallow low permeability gas and the deep tight gas, the percentage would be much higher. There was steep decline in drilling activity in 2007. This decline resulted from a continuing shift away from mature conventional plays.

Table 4 Coalbed Methane Drilling in Western Canada

Sources: CAODC for WCSB Total Gas Wells; ERCB for Coalbed Drilling

	New Canadian Wells in WCSB	New WCSB Coalbed Wells	Coalbed Methane Percent
2004	14,641	781	5%
2005	14,434	2,497	17%
2006	14,205	2,499	18%
2007	11,925	3,055	26%

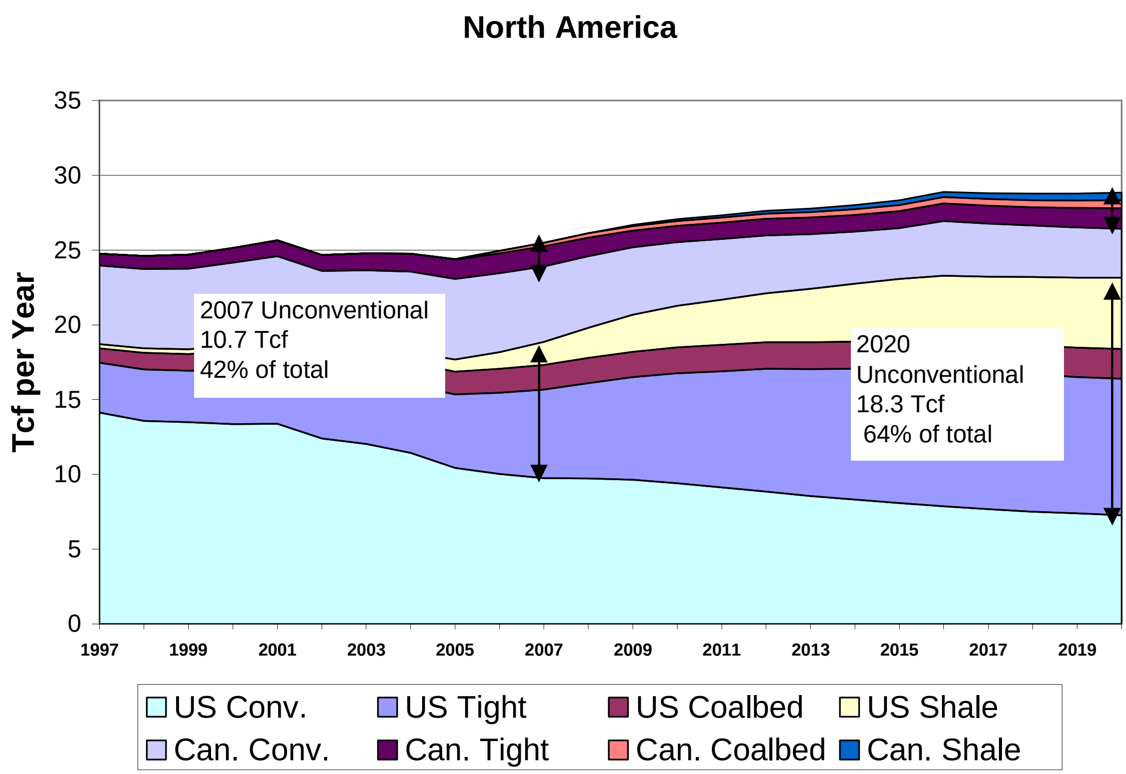
4.5 Expected Future Contribution from Unconventional Natural Gas

Unconventional gas is expected to play a growing role in North American gas production. The ICF Gas Market Model (GMM) is used to forecast supply and demand utilizing a detailed nodal structure. The model balances supply and demand at each node through the forecast. Assumptions about resources, economic growth, oil prices, LNG imports, and other factors are included in the forecast.

An analysis of the regional model production forecast was conducted for the study. The results, summarized in **Figure 12,** show estimated tight gas, coalbed methane, shale gas, and conventional natural gas production for the Lower-48 and Canada through 2020. The chart shows the expected decline in conventional production in both the U.S. and Canada. Tight gas growth will dominate in the U.S., but shale gas growth will also be large. In Canada, unconventional gas production growth is significant. Overall, as shown on the chart, North American unconventional gas grows from 42 percent to 64 percent of the total through 2020.

[9] CAODC, 2008, http://www.caodc.ca

Figure 12 Forecast of North American Natural Gas Production by Type



Following this chart, **Figures 13 though 17** depict the regional data behind the overall forecast. The Rockies forecast is dominated by tight gas growth, while the Mid-Continent is dominated by shale growth. Rockies unconventional production will grow from 83 percent to 94 percent of the total, while Mid-Continent unconventional production will grow from 28 percent to 72 percent of the total. The Gulf Coast, which includes North Texas and East Texas, will be dominated by shale gas and tight gas growth. Gulf Coast unconventional production will increase from 59 percent to 77percent of the total.

The Eastern Interior (all areas east of the Mississippi River, including the Warrior Basin in Alabama) will see a surge in shale gas production from the Marcellus and other plays, and unconventional production will increase from 71 percent to 89 percent of the total. In Western Canada, overall production will decline, but unconventional gas will grow from 25 percent to 49 percent of the total. Shale gas resources in Western Canada are very large but production is forecast to increase somewhat more gradually due to high costs and seasonal drilling restrictions. **Table 5** presents the production forecast data in table format.

Figure 13 Forecast Rockies Natural Gas Production

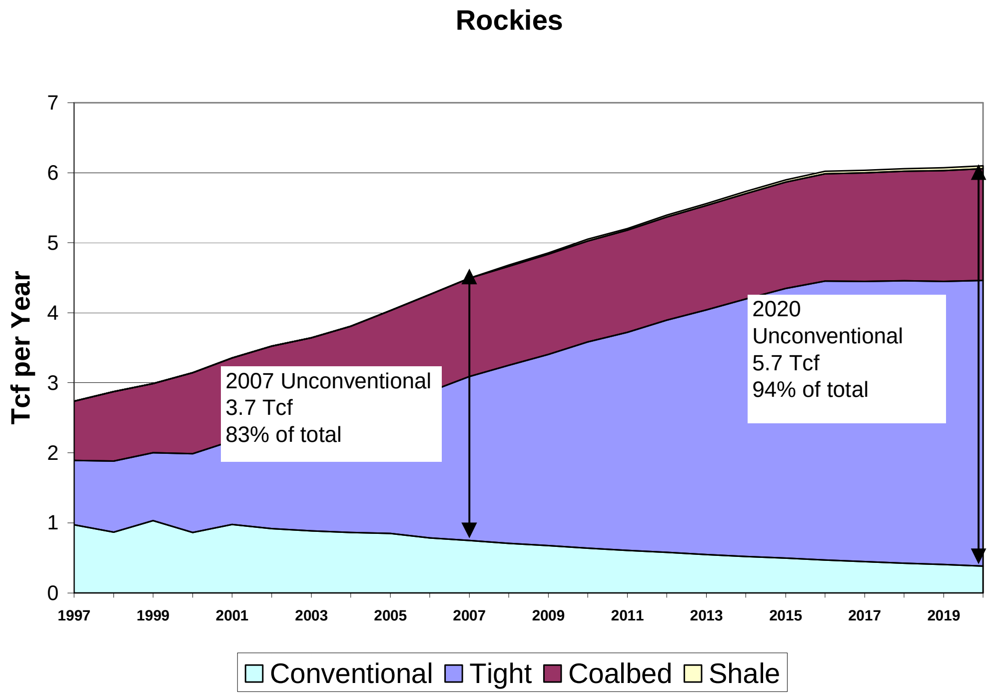


Figure 14 Forecast Mid-Continent Natural Gas Production

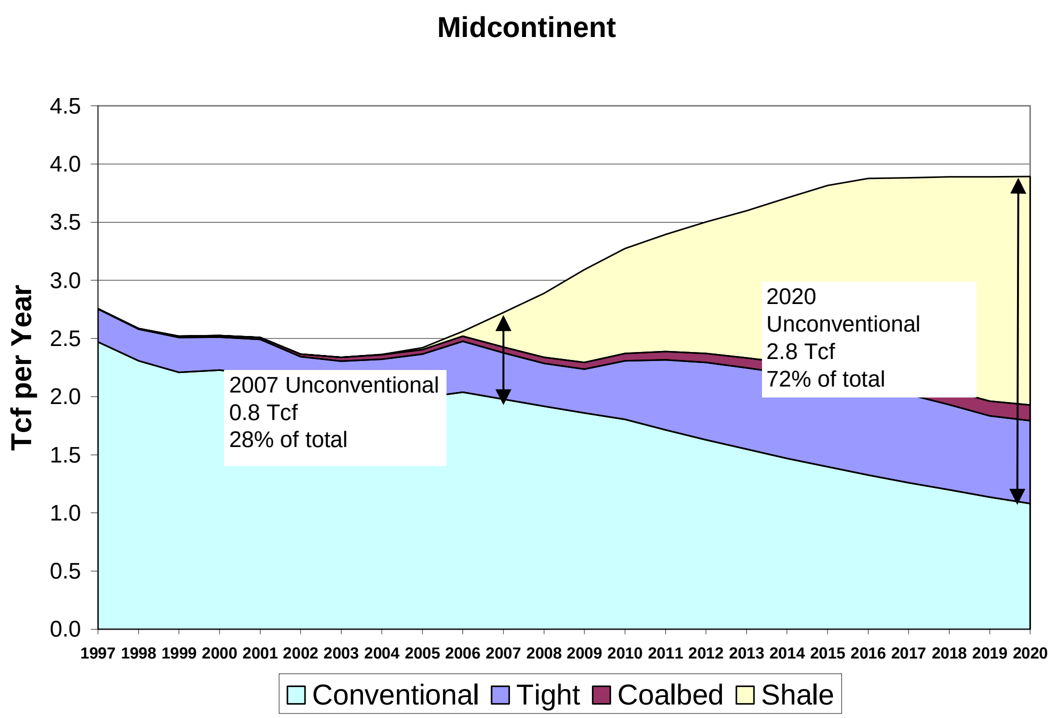


Figure 15 Forecast Gulf Coast and East Texas/Arkla Natural Gas Production

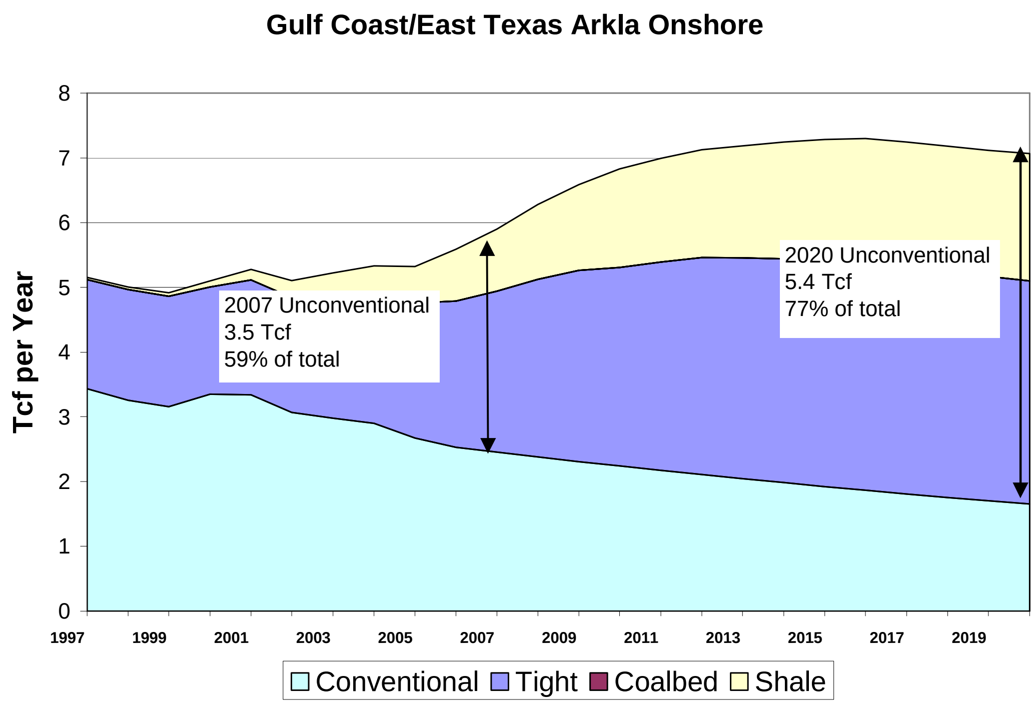


Figure 16 Forecast Eastern Interior Natural Gas Production

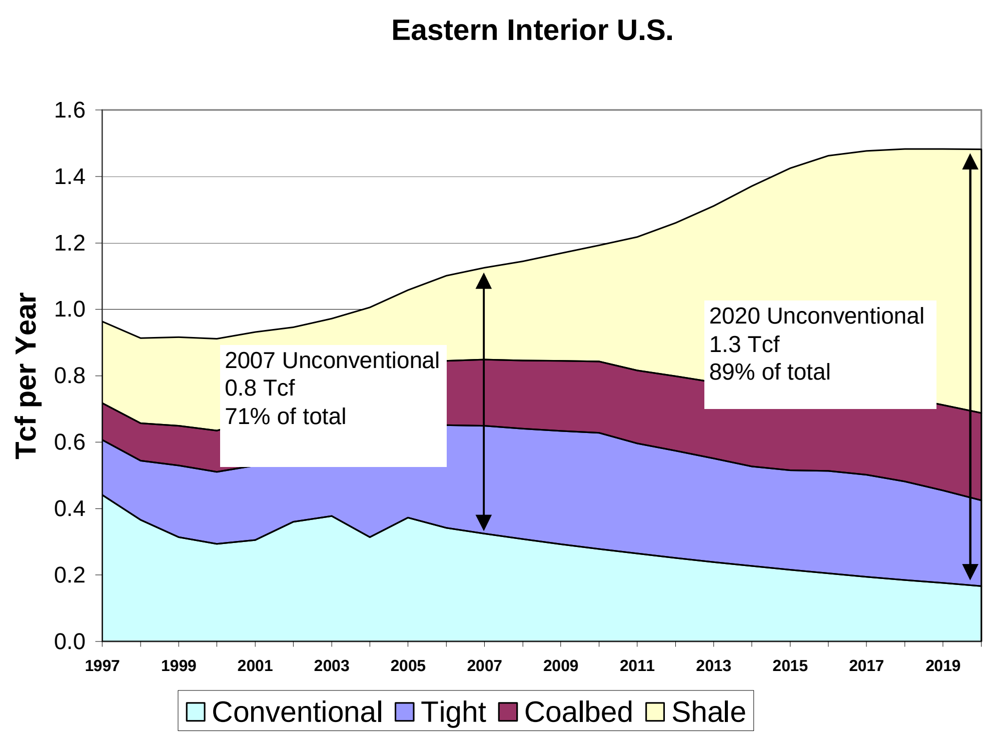


Figure 17 Forecast Western Canada Natural Gas Production

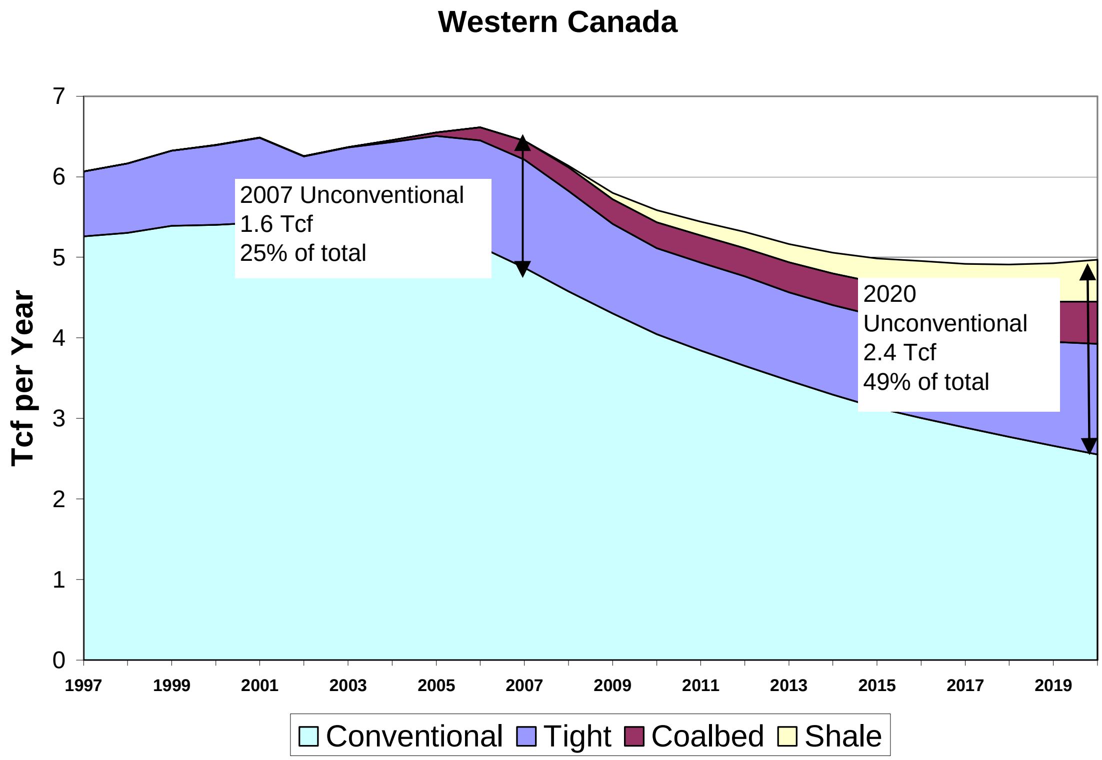


Table 5 Summary of Natural Gas Production Forecast

Tcf per Year		2007	Percent of Total	2020	Percent of Total	2007-2020 Change
Lower-48		Tcf	%	Tcf	%	Tcf
	Conventional	9.75	52%	7.25	31%	-2.50
	Tight	5.92	31%	9.15	40%	3.23
	Coalbed	1.65	9%	1.99	9%	0.34
	Shale	1.54	8%	4.77	21%	3.23
	Total	18.86	100%	23.16	100%	4.30
	Unconv. Total	**9.11**	**48%**	**15.91**	**69%**	**6.80**
Canada		Tcf	%	Tcf	%	Tcf
	Conventional	5.05	76%	3.26	57%	-1.79
	Tight	1.34	20%	1.37	24%	0.03
	Coalbed	0.24	4%	0.52	9%	0.28
	Shale	0.00	0%	0.52	9%	0.52
	Total	6.63	100%	5.67	100%	-0.96
	Unconv. Total	**1.58**	**24%**	**2.41**	**43%**	**0.83**
North America		Tcf	%	Tcf	%	Tcf
	Conventional	14.8	58%	10.51	36%	-4.29
	Tight	7.26	28%	10.52	36%	3.26
	Coalbed	1.89	7%	2.51	9%	0.62
	Shale	1.54	6%	5.29	18%	3.75
	Total	25.49	100%	28.83	100%	3.34
	Unconv. Total	**10.69**	**42%**	**18.32**	**64%**	**7.63**
Regional Data						
Rockies		Tcf	%	Tcf	%	Tcf
	Conventional	0.75	17%	0.38	6%	-0.37
	Tight	2.34	52%	4.08	67%	1.74
	Coalbed	1.4	31%	1.59	26%	0.19
	Shale	0	0%	0.05	1%	0.05
	Total	4.49	100%	6.10	100%	1.61
	Unconv. Total	**3.74**	**83%**	**5.72**	**94%**	**1.98**
Midcontinent		Tcf	%	Tcf	%	Tcf
	Conventional	1.98	73%	1.08	28%	-0.90
	Tight	0.40	15%	0.71	18%	0.31
	Coalbed	0.05	2%	0.13	3%	0.08
	Shale	0.30	11%	1.97	51%	1.67
	Total	2.73	100%	3.89	100%	1.16
	Unconv. Total	**0.75**	**27%**	**2.81**	**72%**	**2.06**
Gulf Coast/East Tex. Onshore		Tcf	%	Tcf	%	Tcf
	Conventional	2.45	42%	1.65	23%	-0.80
	Tight	2.49	42%	3.45	49%	0.96
	Coalbed	0.00	0%	0.00	0%	0.00
	Shale	0.96	16%	1.97	28%	1.01
	Total	5.90	100%	7.07	100%	1.17
	Unconv. Total	**3.45**	**58%**	**5.42**	**77%**	**1.97**
Eastern Interior		Tcf	%	Tcf	%	Tcf
	Conventional	0.33	29%	0.17	11%	-0.16
	Tight	0.32	28%	0.26	18%	-0.06
	Coalbed	0.20	18%	0.26	18%	0.06
	Shale	0.28	25%	0.79	53%	0.51
	Total	1.13	100%	1.48	100%	0.35
	Unconv. Total	**0.80**	**71%**	**1.31**	**89%**	**0.51**
Western Canada		Tcf	%	Tcf	%	Tcf
	Conventional	4.87	76%	2.55	51%	-2.32
	Tight	1.34	21%	1.37	28%	0.03
	Coalbed	0.24	4%	0.52	10%	0.28
	Shale	0.00	0%	0.52	10%	0.52
	Total	6.45	100%	4.96	100%	-1.49
	Unconv. Total	**1.58**	**24%**	**2.41**	**49%**	**0.83**

4.6 Implications of Forecast for Future Drilling, Industry Outlays, and Water Use

The forecast discussed above will require the drilling of tens of thousands of both conventional and unconventional gas wells through 2020 and beyond. It will require large outlays for drilling and completion, well stimulation, and other upstream capital expenditures. Demand for water use in fracturing operations will continue to increase, and disposal or treatment of such water will be required.

In 2007, approximately 31,000 gas wells were drilled in the U.S. ICF estimates that of these, approximately 25,000 wells were unconventional. A total of 300,000 unconventional gas wells will be drilled between 2009 and 2020 to achieve the gas production forecast through 2020. This represents an outlay of $560 billion for drilling and completion costs over the twelve year period. While this is a tremendous outlay by industry, the analysis presented here shows that the North American gas market will support this development.

Artificial stimulation of unconventional gas wells requires a great deal of water. Both tight gas and shale wells require water for fracture stimulation. A horizontal shale well can require up to 3.5 million gallons of gross water injection for fracture stimulation. To the extent that water is recycled, average net water use is less. Details of this process are discussed in Section 5 of this report. Concerns have been raised about the demands placed upon fresh water resources and about disposal or treatment of the water. If one were to assume the use of one million gallons on average per tight gas well and two million gallons per shale well, the ICF drilling forecast through 2020 would require 300 billion gallons of water. However, actual water needs may be much lower, due to water treatment and recycling programs and the possibility of newer stimulation technologies or practices that require less water.

Water use for stimulation has not yet been a major impediment to shale or tight gas development, in most cases. However, future development may be subject to more restrictions or regulation. For example, the issue is being addressed by the state of Pennsylvania, in preparation for an expected large increase in Marcellus Shale drilling activity in that state. State regulators want to ensure that water and disposal is part of the overall state well permitting process.

4.7 Unconventional Natural Gas Production "Upside"

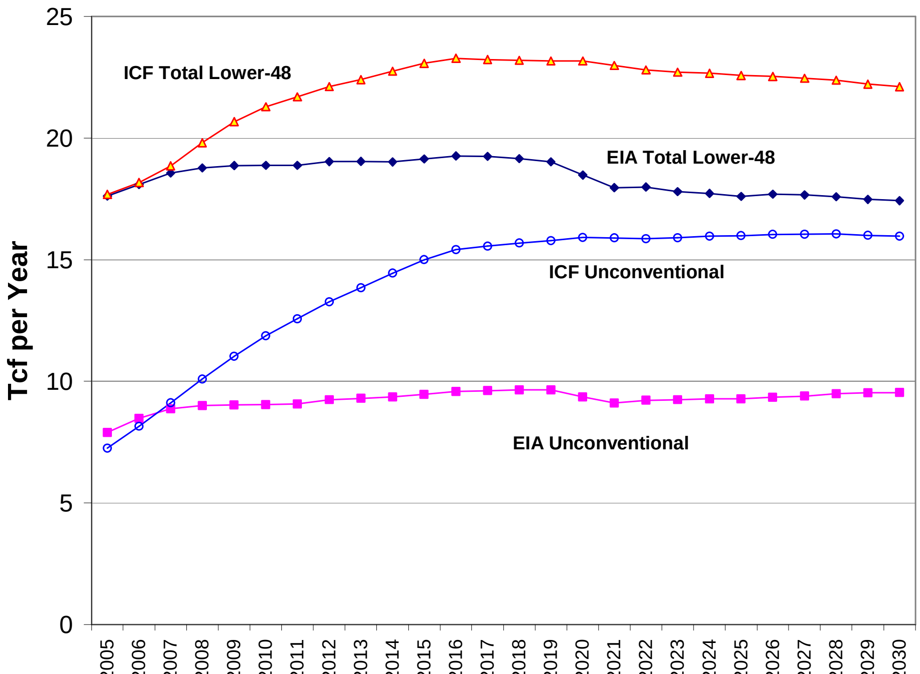
One approach that can be used to estimate a theoretical maximum rate of natural gas production from an unconventional resource is called the "two percent" rule. In this approach, the estimated peak production rate is equivalent to two percent of the recoverable resource within a play. This would equate to 50 years of annual production at this rate, but since there is a ramp up and ramp down period, production extends over a period that is greater than 50 years. This simple rule-of-thumb analysis indicates that relative to our current forecast for 2020, there is an upside potential of roughly an additional 1.5 Tcf per year for the U.S. and 0.7 Tcf per year for Canada, based upon the ICF resource base of unconventional gas.

4.8 Comparison of Forecast to EIA Annual Energy Outlook

Figure 18 is a comparison of the ICF Lower-48 natural gas production forecast with that of the EIA's 2008 Annual Energy Outlook. [10] The EIA forecast for Lower-48 natural gas production is much lower than ICF's forecast, and production peaks at only 19.3 Tcf per year in 2016. Unconventional natural gas production increases only slightly, peaking at 9.6 Tcf in 2018. EIA's forecast of conventional production (not shown) declines from 9.7 Tcf in 2007 to 7.9 Tcf in 2030, while the ICF forecast declines to 6.1 Tcf in 2030.

As is discussed in Section 5, the ICF shale gas resource base is much higher than that of EIA; this likely accounts for most of the difference.

Figure 18 Comparison of ICF Lower-48 Natural Gas Production Forecast with EIA's Annual Energy Outlook



[10] Energy Information Administration, 2008, "Annual Energy Outlook 2008," http://www.eia.doe.gov/oiaf/aeo/

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5 TIGHT GAS, SHALE GAS, AND COALBED METHANE RESOURCES

5.1 Published U.S. Resource Estimates

The previous section of this report presented a summary of *proved natural gas reserves* and annual reserve additions. In addition to proved reserves, there are estimated volumes of undeveloped *recoverable gas resources*. These are estimated volumes of oil and gas that are not yet classified as *proved* but that are expected to be recoverable or producible in the future. The volume of such undeveloped resources is estimated using a range of assessment methodologies, depending upon the nature of the resource and its stage of development.

Several organizations in the U.S. assess the volume of technically recoverable resources from tight gas, shale gas, and coalbed methane, as well as from future conventional fields. The USGS is the principal organization for assessing onshore gas and oil resources. They assess remaining oil and gas resources at the formation or play level. The USGS maintains a website with the latest assessments for each geological basin. [11]

EIA and National Petroleum Council (NPC) also publish assessments of unconventional natural gas. The EIA publishes the Annual Energy Outlook that includes assumptions about natural gas supply and resources. [12] The NPC published its most recent North American natural gas study in 2003, which included extensive documentation about resources and activity trends in the U.S. and Canada. [13] Another prominent U.S. assessment group is the Potential Gas Committee, which publishes a detailed assessment every two years. [14]

[11] USGS National Oil and Gas Assessment; http://energy.cr.usgs.gov/oilgas/noga/
[12] U.S. Energy Information Administration Annual Energy Outlook; http://www.eia.doe.gov/oiaf/aeo/
[13] National Petroleum Council North American Gas Study, 2003; http://www.npc.org/
[14] U.S. Potential Gas Committee; http://www.mines.edu/research/pga/

Table 6 is a summary of Lower-48 unconventional gas assessments, including the ICF assessment. The first three columns are the published assessments of the USGS, EIA, and NPC. The volumes of technically recoverable unconventional resources in these assessments range from 272 to 511 Tcf. The total for the ICF assessment is 624 Tcf, and the primary difference is shown to be ICF's shale gas assessment of 385 Tcf.

The recent emergence of new shale plays and rapid technology changes have made it difficult for the assessment groups to develop assessments that reflect current activity. For example, the NPC assessment was published in 2003 but did not include the Arkoma Basin Fayetteville and Woodford shales because, at the time of publication, these resources had not yet emerged. Of these three published assessments, none evaluated the horizontal drilling potential in the Marcellus play in Appalachia or the Louisiana Haynesville Shale.

Published resource assessments should be viewed with an awareness of rapidly evolving technology and the emergence of large new plays. In addition, former assessed shale resources were based upon an assumption of vertical drilling and older completion technologies. Some of the assessed shale resources in older reports represent the low pressure, shallow part of a shale play that was developed in past decades, as opposed to the deeper, higher pressure area that is now the development target for horizontal drilling.

Table 6 Summary of Published U.S. Unconventional Natural Gas Resource Assessments

TCF
Lower-48 Recoverable Resources

	USGS (Various years)	EIA 2007	NPC 2003	ICF 2008
Tight gas	190	304	178	174
Coalbed methane	70	82	59	65
Shale gas	85	125	35	**385**
Total	345	511	272	624

Sources:

USGS National Oil and Gas Assessment
Energy Information Administration: Supporting materials for the 2007 Annual Energy Outlook
2003 National Petroleum Council Gas Study

Table 7 summarizes the ICF remaining natural gas resource base for the U.S. and Canada onshore and offshore areas, including both conventional and unconventional gas. Offshore areas that have been subject to moratoria are included. Remaining resources include proved reserves, reserve appreciation (reserve addition potential) in existing fields, new conventional fields, tight gas, coalbed methane, and shale gas. The total remaining resource in the U.S. and Canada of 2,338 Tcf represents about 94 years of production at the current annual rate of about 25 Tcf per year.

Table 7 ICF Natural Gas Resource Base

Tcf of Recoverable Resources

	Lower-48	Alaska	U.S. Total	Canada	Total
Remaining proved	196	8	204	58	262
Reserve appreciation and discovered undeveloped	205	36	241	68	309
New conventional fields	503	201	704	152	856
Tight gas	174	0	174	66	240
Coalbed methane	65	57	122	33	155
Shale gas	385	0	385	131	516
Total remaining resources	1,528	302	1,830	508	2,338

Note: Canadian tight gas assumed here to be 30% of new field resources.

Table 8 summarizes the published basin level tight gas assessments of the Lower-48. In general terms, the greatest volumes of assessed tight gas resources are in the northern Rockies, East Texas, the San Juan Basin and Appalachia. However, the quality of resource varies greatly and the comparison can be misleading because the well productivities in the Rockies and some areas of East Texas are much greater than in other basins, especially in Appalachia.

As will be presented in a later section, tight gas is the focus of an intense level of activity in the basins of southwestern Wyoming (Jonah-Pinedale), northwestern Colorado, and northeastern Utah. East Texas activity in the Bossier and Cotton Valley formation continues to expand rapidly. Based upon what has been taking place in just these two areas, the current assessments of tight gas potential look conservative. It is unlikely that they reflect recent advances in stimulation and completion technology.

Table 8 Summary of Lower-48 Tight Gas Assessments

Tcf of Recoverable Resources

Region	Basin	2002-08 USGS	2007 EIA	2003 NPC
Appalachia	Appalachian	45.38	55.98	34.75
Arkla - East Texas	East TX	6.03	31.60	5.86
	Ark-La	0.00	0.00	0.00
	total	6.03	31.60	5.86
Texas Gulf Onshore	Texas Gulf Coast	0.00	14.60	2.61
LA-MS Gulf Coast	LA-MS Salt Basins	0.00	0.00	0.00
Rocky Mtn. Foreland	Piceance	5.02	24.29	9.70
	Uinta	13.81	15.90	13.81
	Powder River	0.79	0.00	0.79
	Wind River	1.69	19.55	0.00
	Green River	80.58	75.42	67.72
	Denver	2.08	9.23	2.08
	total	103.97	144.39	94.10
San Juan Basin	San Juan	26.18	14.93	21.00
Mid-Continent	Anadarko	0.00	13.41	0.00
	Arkoma	0.00	4.10	0.00
	total	0.00	17.51	0.00
Permian Basin	Permian	0.00	13.82	0.00
Williston	N. Cent. Montana	6.12	4.88	5.83
	Williston	0.14	0.00	1.84
	total	6.26	4.88	7.66
West Coast Onshore	Oregon/Wash.	2.12	6.48	11.85
Lower 48		189.94	304.19	177.83
Alaska		0	0	0
U.S. Total		189.94	304.19	177.83

Lower-48 coalbed methane potential is summarized in **Table 9**. The table shows the widespread distribution of coalbed methane resources in the U.S., from the Rockies and San Juan Basin to the Mid-Continent, Gulf Coast, and Appalachian Basin. Regions with the greatest potential include the Rockies, San Juan Basin, Eastern Gulf Coast and Mid-Continent.

Over the past few years, no major new coalbed plays have emerged. Overall, coalbed production has flattened out in the U.S., indicating a certain level of maturity, at least with current technology. However, higher wellhead natural gas prices and increased drilling are resulting in increased production in areas such as the Powder River Basin. In addition, new technologies such as complex directional drilling and multi-lateral completions are just beginning to be used widely for coalbed methane. These new technologies could have a dramatic effect on the economic viability of the resource if used in the future.

Table 9 Summary of Lower-48 Coalbed Methane Assessments

Tcf of Recoverable Resources

Region	Basin	2002-08 USGS	2007 EIA	2003 NPC
Appalachia	C. Appalachian	3.58	3.58	3.48
	N. Appalachian	4.82	4.82	4.68
	total	8.40	8.40	8.16
Eastern Gulf Onshore	Warrior	7.06	4.83	4.47
Michigan-Illinois	Illinois	0.44	0.60	1.58
Arkla Tex +Ft Worth	Bend Arch	0.00	0.00	0.00
Rocky Mtn. Foreland	Piceance	0.37	7.91	3.75
	Uinta	1.95	4.17	2.28
	Raton	1.59	4.03	1.99
	Wind River	0.25	0.00	0.43
	Green River/Hanna	1.53	1.70	2.03
	Powder River	14.26	26.76	20.00
	Big Horn	0.00	0.00	0.00
	Denver, etc	0.00	0.00	0.00
	Paradox	0.00	0.00	0.00
	Plateau. Blk Mesa	0.00	0.00	0.00
	total	19.95	44.57	30.48
TX Gulf Coast	Texas Gulf Cst.	4.06	0.00	0.00
Overthrust Belt	total	0.00	0.00	0.00
San Juan Basin	San Juan Fruitland	23.58	18.12	8.00
	San Juan Menefee	0.66	0.24	0.66
	total	24.24	18.36	8.66
Mid-Continent	Forest City	0.45	w/Chero.	0.44
	Cherokee	1.91	2.39	1.86
	Arkoma	2.64	3.23	2.56
	Anadarko	0.00	0.00	0.00
	total	5.00	5.62	4.86
West Coast Onshore	Western Oregon	0.71	0.00	0.68
Lower 48		69.86	82.38	58.89
Alaska		18.06	0.00	57.00
U.S.		87.92	82.38	115.89

Table 10 summarizes the published U.S. shale gas assessments. (A detailed comparison with the ICF assessment is presented in the next section). The initial area of shale gas development in the U.S. was the Appalachian Basin, where production began before 1900. In a recent assessment, the USGS assessed the low pressure vertical drilling portion of the resource at 12 Tcf. The Antrim Shale in Michigan also has substantial remaining resources, although the volume of Antrim production is lower than many analysts had predicted a decade ago. The Barnett Shale of the Fort Worth Basin in Texas was assessed at 26 Tcf by the USGS in 2003. Based upon recent trends of development in the Barnett and the successful expansion of that play, this assessment is likely very conservative.

The USGS has not yet assessed the potential of either the Fayetteville Shale or the Woodford Shale horizontal drilling plays in the Arkoma Basin of Arkansas and eastern Oklahoma. The EIA included resource estimates for these two plays of 29 Tcf and 16 Tcf, respectively. [15]

The USGS has not yet assessed the Appalachian horizontal Marcellus Shale or the Haynesville Shale in northwestern Louisiana. A recent trade press reported that a study by researchers at Penn State and the State University of New York estimated the gas-in-place of the Marcellus as ranging from 168 Tcf to 516 Tcf with recoverable resources of 50 Tcf. [16] (Gas-in-place is the total amount of natural gas contained within a reservoir, and is a greater volume than recoverable gas). Recent trade press has indicated that the Haynesville Shale in northwestern Louisiana and East Texas has recoverable resources of at least 20 Tcf. These plays are discussed in detail in the next section of this report.

A large area of thick Barnett and Woodford Shale is present in the Permian Basin of West Texas. Recently, the USGS assessed this area as having 35 Tcf of potential production.

The potential of the Rocky Mountain shale gas is largely unknown. EIA, however, has estimated 10 Tcf of Lewis shale potential in the San Juan Basin of northwestern New Mexico. Thick, extensive Cretaceous age shales are present across the Rockies but are just now being evaluated with horizontal drilling. Rockies gas shales are often interbedded with low-permeability sandstone gas reservoirs, making the distinction between tight gas and shale gas difficult.

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[15] Supporting materials for the 2007 EIA Annual Energy Outlook and updated information provided to ICF.
[16] *Gas Daily*, March 19, 2008.

Table 10 Published Lower-48 Shale Gas Assessments

Tcf of Recoverable Resources

Region	Basin	2002-08 USGS	2007 EIA	2003 NPC
Appalachia	Appalachian Vertical Low Pressure	12.20	14.41	16.99
	Appalachian Marcellus Horizontal	not assessed	not assessed	not assessed
	Appalachian Huron Horizontal	not assessed	not assessed	not assessed
Texas and LA Gulf Coast	Haynesville Shale	not assessed	not assessed	not assessed
Warrior Basin, AL and MS	Floyd and Conasauga Shales	not assessed	not assessed	not assessed
Michigan-Illinois	MIchigan Antrim	7.47	10.55	7.37
	Illinois New Albany	3.79	2.04	1.76
	Cincinnati Arch	0.00	0.75	1.29
	total	11.26	13.34	10.43
North Texas	Fort Worth Barnett	26.20	38.01	7.00
Mid-Continent	Arkoma - Arkansas	not assessed	29.18	not assessed
	Arkoma - Oklahoma	not assessed	15.79	not assessed
	total	0.00	44.97	0.00
Permian Basin	Barnett and Woodford Horizontal	35.13	not assessed	not assessed
Williston	Williston Niobrara	0.00	3.85	0.00
Rockies	San Juan Lewis	0.00	10.41	0.00
	Raton Basin Pierre	not assessed	not assessed	not assessed
Pacific Onshore	San Joaquin Basin	0.00	0	0.32
Lower 48 total		84.79	124.99	34.74
Alaska		0	0	0
U.S. total		84.79	124.99	34.74

5.2 Published Canadian Resource Estimates

Canada contains vast undeveloped resources of unconventional natural gas. As with conventional natural gas resources, coalbed, tight, and shale gas resources are concentrated in the Western Canadian Sedimentary Basin in Alberta and British Columbia. While coalbed methane in Canada has been assessed, much work remains to evaluate tight gas and shale gas resources, recovery, and economic viability.

Table 11 summarizes some recently published natural gas-in-place volumes by several groups. Organizations that have developed assessments in recent years include the National Energy Board, the Alberta EUB (now ERCB), the Alberta Geological Survey, the Canadian Gas Potential Committee, and the Gas Technology Institute. Organizations such as the Canadian Association of

Petroleum Producers (CAPP) and the Canadian Society for Unconventional Gas (CSUG) have published summaries as well.

Table 11 shows that tight gas has been assessed at 430 Tcf, as cited in a paper by Gatens.[17] CSUG has an assessment of tight gas (sandstone) potential in the Deep Basin of western Canada. [18] Their assessment of undiscovered recoverable resources is 23 Tcf for that tight gas play. Coalbed methane in Canada has been assessed by the Alberta Energy Resources Conservation Board (ERCB) at 500 Tcf of gas-in-place.[19] As shown in the table, most of the assessed resource is in the Mannville formation (350 Tcf). A much smaller resource (84 Tcf) is assigned to the Horseshoe Canyon play; it represents most of the current production of over 650 MMcf per day. In 2002 the Gas Technology Institute carried out an assessment of the shale gas potential of Western Canada. [20] This report is available from GTI through their website and the details are not presented here. However, the overall assessment of 860 Tcf of gas-in-place is commonly cited.

Table 11 Published Canadian Unconventional Natural Gas Assessments

Tcf of Gas-In-Place

Category	Tcf Gas-in-Place	Source (see footnotes)
Tight	430	Petrel Robertson as referenced in Gatens, 2008 and CAPP, 2007.
Coalbed Methane	500	Alberta ERCB/EUB and NEB as referenced in Gatens, 2008
Shale Gas	860	Gas Technology Institute, 2002
Interval Breakout of Western Canada CBM Gas-in-Place (total of 454 Tcf; differs from above assessment)		
Total WSCB	454	ERCB/EUB and AGS as referenced in Encana, 2008
Mannville	350	
Horseshoe Canyon	84	
Ardley	20	

References:

Gatens, Michael, 2008, "The Role of Unconventional Gas in North America," CERI 2008 Natural Gas Conference, February 25-26, Calgary, Alberta, Canada.
Encana, 2008, "Raymond James Oil Sands of Canada Conference," New York, May 5, 2008; available on company website: http://www.encana.com/investors/presentationsevents/index.htm
Gas Technology Institute, 2002, "Shale Gas Potential of Selected Upper Cretaceous, Jurassic, and Devonian Shale Formations in the WCSB of Western Canada: Implications for Shale Gas Production," GRI Report 02/0233, December, 2002.
CAPP, 2007, " Oil and Gas Benefits to Alberta and Canada," June 2007 report by CAPP/SEPAC.

[17] Gatens, Michael, 2008, "The Role of Unconventional Gas in North America," CERI 2008 Natural Gas Conference slides, February 25-26, 2008, Calgary, Alberta Canada.
[18] Canadian Society for Unconventional Gas, 2008, "Western Canada Tight Gas Resource Characterization Project – Deep Basin Tight Gas," CSUG slides, March 12, 2008.
[19] Gatens, ibid.
[20] Gas Technology Institute, 2002, "Shale Gas Potential of Selected Upper Cretaceous, Jurassic, and Devonian Shale Formations in the WCSB of Western Canada – Implications for Shale Gas Production," GTI/GRI Report 02/0233, December 2002. http://www.gastechnology.org

Table 12 shows the gas-in-place and recovery assessment prepared for the 2003 National Petroleum Council study. The gas-in-place assessment was prepared by GTI. The table shows that some basic assumptions on fraction of area drillable and recovery factor were used to pare the gas-in-place down to recoverable natural gas. The recoverable gas included in the model was 17 Tcf. Well recoveries were assumed to be low and were based on vertical wells. Horizontal well characterization was not made.

The Wilrich, Doig, and Montney formations were evaluated in both the Alberta and British Columbia parts of the basin. However, the Devonian Shale was evaluated only in Alberta. Therefore, any resources from the new British Columbia Devonian Shale would be incremental. The total assessment for the Montney formation gas-in-place is 187 Tcf.

Table 12 WCSB Shale Vertical Well Assessment for the 2003 National Petroleum Council Study

Play	G.I.P. (Bcf)	fraction drillable	GIP in drillable areas (Bcf)	Recovery factor	Recovery (Bcf)
Upper K Wilrich	156,000	0.20	31,200	0.10	3,120
Triassic Doig	10,700	0.20	2,140	0.10	214
Triassic Doig Phosphate	129,000	0.20	25,800	0.10	2,580
Triassic Montney	187,000	0.20	37,400	0.10	3,740
Devonian Ireton/Duvernay /1	377,000	0.20	75,400	0.10	7,540
total	859,700		171,940		17,194

1. The Devonian Shale gas-in-place is only for Alberta. It excludes the new Horn River Basin play.

5.3 Technology Advances Impacting Tight Gas, Coalbed Methane, and Shale Gas

In the early decades of oil and natural gas development, hydrocarbon reservoirs were developed using vertical wells of conventional diameter by using conventional rotary drilling tools. Gas well spacing was generally one well per square mile. Well stimulation was either not used or it was based upon low technology methods such as explosives or acid stimulation.

In recent decades, tremendous advances have been made in all areas of drilling, stimulation, and well completion. The most important areas of current technology are directional and horizontal drilling and advanced fracture stimulation.

Directional and Horizontal Drilling

Currently, the most active shale gas plays such as the Barnett Shale in the Fort Worth Basin are being drilled directionally and completed horizontally. Directional drilling has been around for decades but has seen great strides in terms of downhole directional control and placement of the wellbore within a thin zone. Typically, a well is drilled vertically to a depth of perhaps several thousand feet. After drilling vertically, the well is steered horizontally and may be drilled for several thousand feet to 5,000 feet or more within the shale formation.

The process of guiding the bit during directional drilling is termed "geo-steering" and is accomplished through real-time data acquisition. This technique is allowing companies to accurately place a horizontal well within a formation only a few feet thick.

Increasingly, tight gas development in the Rockies is based upon drilling numerous directional wellbores from a single surface location, rather than drilling one wellbore from a surface location. This technology differs from horizontal drilling where the objective is to have a horizontal completion zone. The approach is used in the Jonah-Pinedale field of southwestern Wyoming, and is especially useful in areas where surface disturbance must be minimized.

Well Stimulation

After drilling an unconventional gas well, it is necessary to fracture (stimulate) the formation to allow the gas to more easily flow to the wellbore. Hydraulic fracturing (the pumping of fluid into the well under very high pressure until the formation fractures) is the key in tight gas and shale gas development. Coalbed methane wells often are artificially stimulated. Most tight reservoirs must be fractured before they will flow at commercial rates. Twenty or more years ago, industry used thick cross-linked fluids containing high volumes of proppant (sand or other material used to prop open artificial fractures so they do not close under natural pressure), but these stimulation treatments were very expensive. Today, "slick-water" fracturing techniques using high volumes of water and lower volumes of proppant are used instead.[21] Slick water techniques employ additives such as surfactants to reduce friction and facilitate fracturing. **Figure 19** illustrates the techniques used to artificially fracture Mid-Continent shale formations such as the Fayetteville Shale play in the Arkoma Basin. In this method, the horizontal portion of the well often exceeds 2,000 feet in length, and four or more vertical fracture zones are created by successive artificial stimulation procedures.

Another method being used is the sequential stimulation of up to several dozen zones in a single vertical tight gas well. This method is being used to develop thick sand packages in northwestern Colorado and southwestern Wyoming. **Figure 20** illustrates the fracturing technique being used to develop tight sands in this region.

[21] Oil and Gas Investor, 2006, "Tight Gas," March 2006 supplement publication to Oil and Gas Investor.

Figure 19 Shale Fracturing in a Horizontal Wellbore

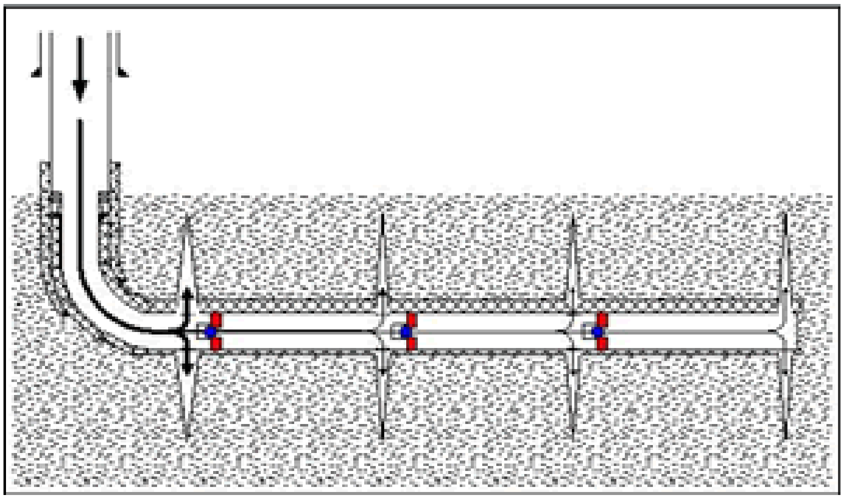
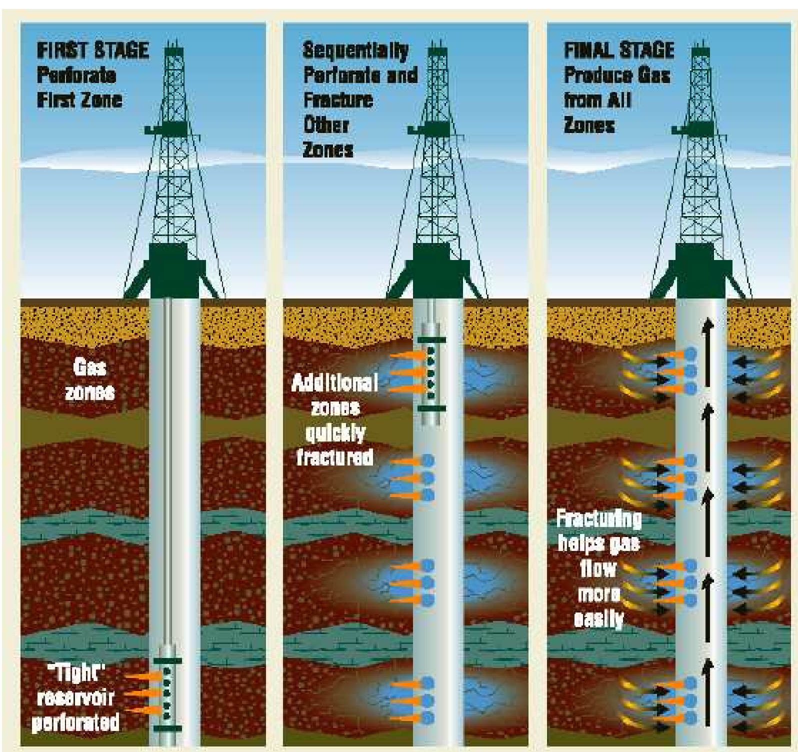


Figure 20 Stimulation of a Vertical Tight Sand Well



Water Use for Stimulation

Artificial stimulation of an unconventional gas well requires large volumes of water. In some cases, concerns have been raised about the demands placed upon water resources for this purpose, and also about disposal or treatment of the water, and related environmental issues.

Hydraulic fracturing water is fresh water that has been treated with a friction reducer and other agents to facilitate fracturing. The so-called slick water fracturing was used in the Barnett by 1997 and was found to be very successful. [22] Slick water fracturing of a vertical well can use 1.2 million gallons of water while a horizontal well can use 3.5 million gallons. The wells may also be fractured again after a period of natural gas production. In 2005, about 60 percent of water used for Barnett Shale development was from groundwater sources and 40 percent was from surface sources. [23] Most Barnett Shale well stimulation water is now hauled off site for deep well injection into zones far below sources of drinking water. [24] To address environmental concerns related to demands on regional water sources as well as disposal, operators are increasingly recycling water to reduce net water use.

Underbalanced Drilling

Underbalanced drilling relies upon drilling fluids that are lower in density and downhole pressure than the fluids in the reservoir rock. This method results in less invasion of drilling fluid into the reservoir, and therefore preserves the reservoir and allows for higher rates of natural gas production and more consistent well recoveries.

Multi-Lateral Drilling and Completion

An emerging trend for some horizontal shale plays is to drill multiple horizontal laterals from one vertical wellbore. For example, Equitable Resources is exploring the application of using air drilling (drilling with compressed air rather than drilling fluid) with multi-laterals to develop the low pressure Huron Shale play in Appalachia. Artificial fracturing of the well is not used in this approach. Instead, they are drilling multiple horizontal segments to access a naturally fractured section. [25] The method is economically viable because in this play it is possible to use inexpensive air drilling rather than conventional drilling.

Multi-laterals can also have applications where surface access is limited and there is a need to utilize a limited number of vertical wells.

Pinnate Drilling

Pinnate drilling is a form of multi-lateral horizontal drilling that is used to develop coalbed methane in Appalachia. Pioneered by CDX Gas, the method has achieved excellent results and shows great promise in contacting and recovering a much higher percentage of gas-in-place than vertical drilling or other types of horizontal drilling. Pinnate technology involves drilling a pair of boreholes at each surface location. There is a vertical borehole and a nearby directional borehole that

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[22] Railroad Commission of Texas: http://www.rrc.state.tx.us/

[23] Texas Water Development Board, 2007, "Northern Trinity/Woodbine GAM Assessment of Groundwater Use in the Northern Trinity Aquifer Due to Urban Growth and Barnett Shale Development," January, 2007 http://www.twdb.state.tx.us/RWPG/rpgm_rpts/0604830613_BarnetShale.pdf

[24] Texas Water Development Board, 2007, ibid. page 2-45.

[25] Oil and Gas Investor, June, 2008.

contacts the coal bed horizontally. [26] Horizontal multi-lateral drilling within the coal bed follows a pattern that is similar to the veins on a leaf. Once the pinnate pattern is completed, gas is produced through the vertical borehole. Production of gas through the vertical borehole allows efficient de-watering of the coal seam.

Slim-Hole and Micro-Hole Drilling

Coiled tubing micro-hole technology uses a coiled tubing rig and small diameter and less cumbersome drilling equipment that greatly reduces drilling time and costs. A coiled tubing rig does not use traditional rigid drillpipe with a rotary bit, but instead uses a coil of tubing that is run into the hole with a steerable assembly and rotary bit powered by drilling fluid pumped downhole. Much of the technology is downsized versions of existing standard diameter drilling equipment, including bits, motors, and bottom hole assemblies.[27] Drilling is accomplished utilizing continuous 2 5/8 inch coiled tubing. The bit is turned by turbines that are powered by the mud circulation.

GTI, with the support of DOE, has completed successful field testing of coiled tubing micro-hole drilling technology in the Niobrara gas play of Kansas and Colorado. This technology has the potential to substantially reduce the costs to drill and complete gas wells, and to increase U.S. future gas production. In addition, the reduced environmental footprint should result in the ability to access resources in areas where environmental concerns would have been an impediment using traditional technology.

Technologies include "built for drilling" coiled tubing (CT) rigs, specialized bits, and bottom hole assemblies to allow for steering, logging and communication with the surface. Well bores can be vertical or can have substantial horizontal components. Technologies to facilitate longer horizontal components are under development, and include downhole "tractors" to provide additional force on the bit.

Biologic Production Enhancement

It may be possible to enhance methane production from coal beds and shales by injecting bio-engineered microbes into the reservoir. Such microbes would convert additional organic matter into methane. Research into this process is underway and may proved commercially viable over the next few years.

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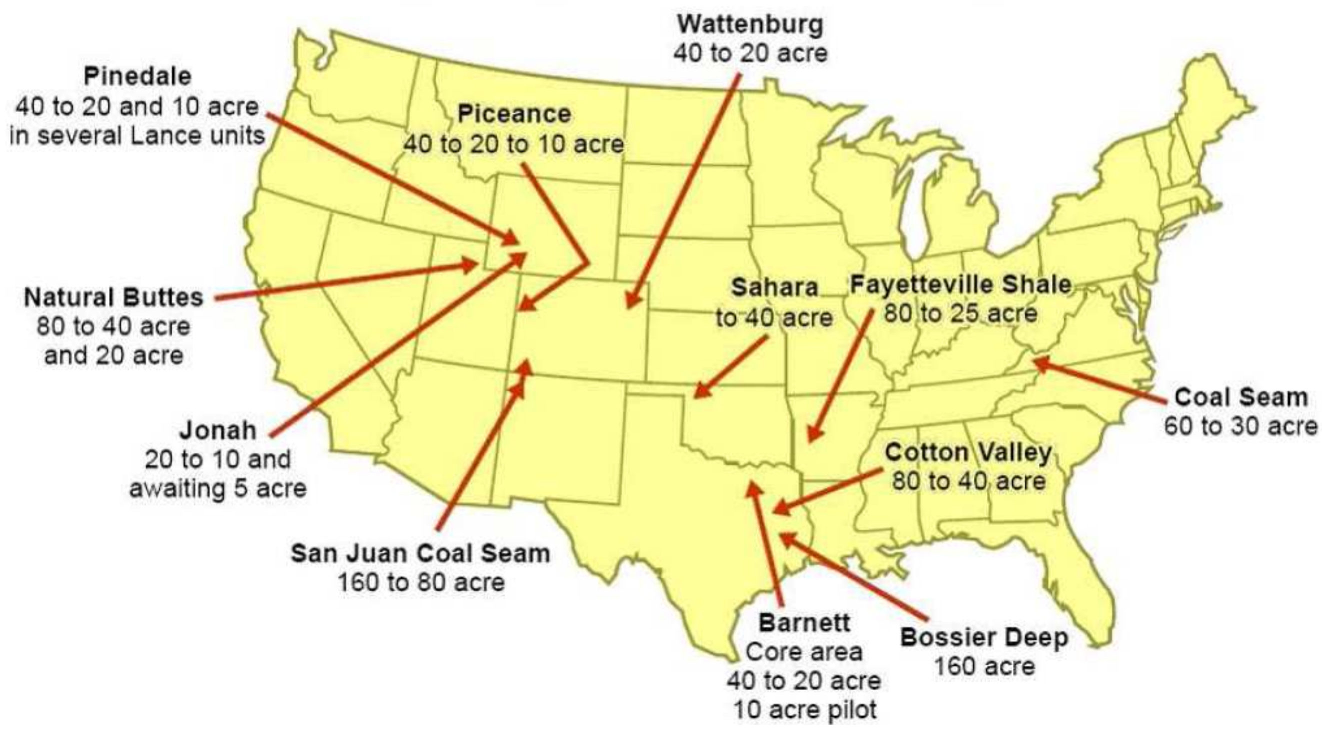
[26] CDX Gas website: http://www.cdxgas.com/technology.php
[27] Duttlinger, D.F., 2006, "Microhole Drilling Shaves Well Costs," E&P Magazine, February, 2006.

Infill Drilling

Infill drilling of tight gas reservoirs has played a major role in gas development activity in recent years and there is excellent potential to reduce further the well spacing in many areas. Infill drilling to well spacings as small as ten acres per well is occurring at Jonah-Pinedale in Wyoming. A map of unconventional natural gas well spacing for various plays is shown in **Figure 21**. The map shows recent trends in well spacing for various plays, with the more recent development occurring on smaller spacings.

Figure 21 Map Showing Well Spacing for Unconventional Natural Gas Plays

Source: IHS



5.4 Comparison of Selected Shale Play Assessments

The assessment of shale gas potential in the U.S. and Canada is a work in progress and there is a long way to go to understand remaining potential and implications for future natural gas production. The volumes of gas-in-place are extremely large, and a small difference in the estimated percentage of gas-in-place that is recoverable has a huge impact on estimates of recoverable resources. In addition, each shale basin is different geologically, and the science of understanding the parameters that control production is still evolving.

ICF's gas market models require assumptions about remaining resources in each North American Basin. We have utilized USGS and Canadian government agency assessments, or modified versions of USGS. assessments developed in industry studies such as the 2003 NPC Study. [28] As shown in **Table 13**, the USGS. has not published assessments of the Arkoma Basin shale, and just recently published a study of West Texas Shale. [29] Their Barnett Shale assessment of 26 Tcf is much higher than previous assessments, but is now considered conservative. The 2003 NPC study included only 7 Tcf for the Barnett, reflecting the understanding of that time and illustrating the evolution of resource assessment for shale gas. NPC did not include the Arkoma Basin shale, since it was not yet active.

The right hand column of **Table 13** presents the results of the ICF analysis of potential recovery (production) from these shale plays. The recoverable resource volumes shown represent the result of volumetric assessments that include analysis of shale area, thickness, depth, organic content, and other variables and include only those areas within the gas generation zone of thermal maturity (areas where the thermal history has been adequate for gas generation). In established plays, operator-published and database-derived well recoveries have been used to calibrate the assessments. The recoverable resource is also dependent upon well spacing. In this report, ICF assumed 40 acre spacing for horizontal drilling, with 40 acre infill wells recovering less gas than the original 80 acre wells.

Although the recoverable resource volumes are very large, it should be noted that this may not translate into economic development or large scale gas production. For example, industry has been working for several years to establish economic production in West Texas, but that has not yet occurred on a significant scale. Unfortunately, little information has been published to date on efforts to establish production in that play, and what difficulties may have been encountered.

[28] National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," NPC, Washington, DC. http://www.npc.org
[29] USGS, 2008,"Assessment of Undiscovered Oil and Gas Resources of the Permian Basin Province of West Texas and Southeast New Mexico," USGS Fact Sheet 2007-3115, 2008.

Table 13 Comparison of Recent U.S. Shale Gas Assessments – Selected Plays (Not Including Recently Announced Frontier Plays)

Recoverable Resources - Tcf

	USGS (Various Years)	2003 National Petroleum Council	Current ICF
Barnett - Fort Worth Basin	26	7	107
Fayetteville - Arkansas	not assessed	not assessed	58
Woodford - Oklahoma	not assessed	not assessed	53
Woodford/ Barnett - West Texas	35	not assessed	10

Details of 2007 USGS Assessment of West Texas:

Delaware Basin Woodford	15.1
Delaware Basin Barnett	17.2
Delaware Basin Wolfcamp	0
Total Delaware Basin	32.3
Midland Basin Woodford/Barnett	2.8
Total	35.1

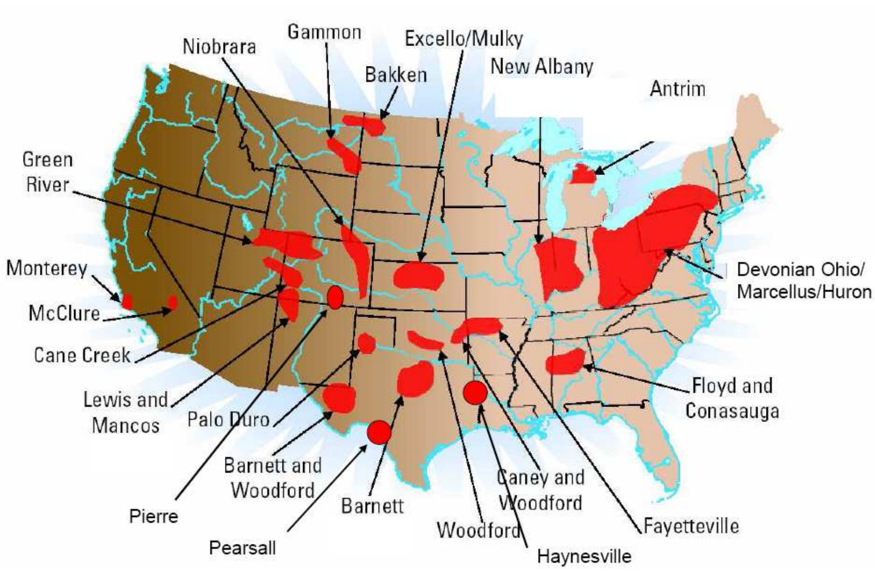
Notes: ICF assessments based upon volumetrics and are based upon 40 acre horizontal wells or in the case of West Texas, 80 acres. USGS assessment is from 2008 publication titled: "Assessment of Undiscovered Oil and Gas Resources of the Permian Basin Province of West Texas and Southeast New Mexico, 2007," USGS Fact Sheet 2007-3115, February, 2008.

5.5 Preliminary Assessment of Potential in Frontier Shale Gas Plays

The term *play* refers to a specific formation or geological feature that is targeted in a part of a basin for exploration and development. In the spring of 2008, a flurry of company announcements were made about emerging shale gas plays across North America. The successful drilling results in a variety of regions, combined with the vast extent and volume of the shale formations, has lead to a new perception of future U.S. and Canadian natural gas supply and production potential. **Figure 22** is a map of the major shale gas basins in the U.S. This map shows the widespread distribution of shale plays that may impact future production.

Figure 22 Shale Gas Basins of the U.S.

Source: Schlumberger presentation, 2005 [30] .



New plays include the following:

- Appalachian Basin Marcellus Shale
- Appalachian Basin Huron Shale
- Appalachian Basin Utica Shale
- Gulf Coast Haynesville Shale
- British Columbia Devonian Shale
- British Columbia Montney Shale
- Raton Basin Pierre Shale

Only fragmentary information relating to ultimate play resource volumes for the new horizontal plays has been published. Most of what is available from industry relates to the results of initial well tests, established acreage positions, and some information on drilling plans.

USGS and Canadian agencies have published assessments through the years, but these assessments are outdated and are not based upon horizontal drilling and current technologies.   For example,

[30] Schlumberger, 2005, "Shale Gas," company white paper
http://www.slb.com/media/services/solutions/reservoir/shale_gas.pdf

the USGS assessed the natural gas-in-place and recoverable resources of the Marcellus Shale in Appalachia, but the assessment was based upon vertical drilling in the lower pressure portions of the play. It did not assess the high pressure, horizontal drilling play.

In an effort to evaluate the horizontal drilling shale gas resource base, ICF has developed a preliminary analysis of factors important to gas recovery, including area, thickness, gas-in-place, and well recovery.

Table 14 shows the ICF volumetric analysis of natural gas-in-place and recovery for the established and emerging shale gas plays of North America. The upper portion of the table shows the results of studies that were completed in 2007-08 using a variety of sources including published geologic and shale property maps. These maps were used to create analytic "cells" characterized by a specific surface area, thickness, depth, pressure, organic content, and estimated gas-in-place per unit volume.

The analysis of emerging shale plays is based upon sparse information and is therefore much more uncertain in terms of both gas-in-place and potential recovery. For plays such as the Louisiana Haynesville, there is very little geologic information in the public domain. Information available for analysis includes industry press releases, statements, and slide presentations showing the potential play outline, combined with information on average shale thickness. [31] For the Marcellus, the analysis is based in part upon the 2002 USGS assessment of gas-in-place, along with an ICF estimate of the area of shale with favorable maturity. [32] For the Pierre Shale in the Raton Basin, the data are based in part on a presentation by Pioneer Natural Resources. [33] More information on each of these plays is presented in a later section of this report.

Although the analysis shown in the table is preliminary and is subject to change, it illustrates the potential magnitude of the shale gas resource. For example, the calculated unrisked (not reduced for geologic risk) gas-in-place of the Barnett is 1,150 Tcf, but this only represents about 22 percent of the total gas-in-place of all assessed plays. Further, it is likely that additional plays will emerge in the future.

[31] Slide presentations from El Paso and Exco Resources, and Gas Daily articles and statements and slides from Chesapeake Energy.
[32] USGS, 2002, "Eastern Interior Province Natural Gas Workshop," National Petroleum Council Supply Task Group presentation, USGS, January, 2003.
[33] Pioneer Natural Resources, 2008, Company slides presented at Howard Weil Energy Conference, April 9, 2008.

Table 14 Analysis of Existing and Emerging Shale Formation Volumes and Gas- in- Place

Preliminary ICF estimates for emerging plays based upon limited data
Assumes horizontal development wells generally on 40-acre spacing
Does not include all shale plays in North America

Play	Gross Play Area Sq. Mi.	Basin Avg. Shale Thickness/1 Feet	Shale Volume Cubic Mi.	"Unrisked" Gas in Place/2 Tcf	"Risked" Gas in Place/2 Tcf	**Technical Recovery Tcf**
Plays Evaluated Through Mapping						
Fort Worth Barnett	7,750	250	367	1,150	538	**107**
Fayetteville	9,100	106	183	309	216	**58**
Woodford	11,600	180	395	719	169	**53**
West Texas Barnett /3	5,100	441	426	1,302	206	**10**
Total				**3,480**	**1,129**	**229**
`						
Emerging Plays With Preliminary Volumetric and Gas-in-Place Estimates						
Appalachian Marcellus /4	19,000	150	540	350	210	**63**
Appalachian Utica	7,500	350	497	75	23	**7**
Louisiana Haynesville	5,000	200	189	400	160	**31**
Colorado Pierre	250	1,500	71	35	11	**2.0**
BC Devonian Muskwa	3,000	350	199	750	300	**60**
WCSB Montney Horizontal	2,000	400	152	150	60	**12**
Total				**1,760**	**763**	**175**

Notes:
1. Average thickness includes all mapped areas of the play with potential. Areas developed first are typically thicker.
2. Unrisked gas in place is the total calculated gas in place using volumetrics. Risked gas in place is the value after a geologic risk factor is applied. The geologic risk factor essentially chops out a certain portion of the area due to factors such as erosion, faulting, extreme depth, and other factors. Fringe areas of a play that are not yet productive have higher geologic risk.
3. West Texas shale assumed to be developed on 80 acre spacing.
4. USGS assessed the Marcellus at 295 Tcf of gas in place in 2002. Actual total area is 54,000 sq. miles, but above area (19,000 sq. mi.) is based on the area assumed to have geologic and economic potential based on USGS maps.

5.6 Comparison of ICF Lower-48 Shale Play Assessments with Published Assessments

Table 15 compares the current ICF assessment of technically recoverable shale gas resources of the Lower-48 with the mean assessments of the USGS, 2008 EIA, 2003 NPC, and a recently published study prepared for the American Clean Skies Foundation (ACSF). [34] It should be noted that differences in assessments may reflect the public information available at the time of each assessment and do not necessarily reflect different interpretations of the same data.

The ICF shale assessment is the largest of the mean assessments at 385 Tcf. One reason is that the ICF assessment covers more plays and basins, especially when compared with USGS, EIA [35], and NPC. [36] Also shown on the table for comparison is the "maximum" assessment published in the Clean Skies report. That assessment was based on maximum operator estimates for each play and totals 842 Tcf for the Lower-48. Most of the difference between the Clean Skies mean and maximum assessments is in the Appalachian Marcellus Shale and the Louisiana Haynesville Shale. The major differences by play area (mean assessments) are as follows:

Barnett Shale: The ICF assessment is by far the largest. Our assessment is based upon internal mapping and well level production analysis. It was recently increased based upon production performance and the high level of success over a wider area than previously forecast. Production projections from the Barnett of 6 to 7 Bcf per day are consistent with this volume of resource and forecast activity. The USGS assessment of 26 Tcf was published in 2004 and does not come close to capturing the implications of the play's success over the past few years. It is very likely that the recovery per well and well spacing assumptions in that study were too conservative. The Clean Skies study also included the USGS assessment, while EIA's assessment of 38 Tcf appears to be an estimate based upon the USGS plus 50 percent. The 7 Tcf assessment of the NPC was based upon an older USGS study that was based upon vertical drilling.

Fayetteville Shale: The ICF assessment of 58 Tcf is the largest and was also based upon detailed mapping by ICF and well level production analysis. It incorporates geologic risk that reduces the estimated volume of recoverable gas in outlying areas. The USGS has not assessed the Fayetteville. EIA has assessed this play at 29 Tcf while the Clean Skies report has 26 Tcf. The origin of these assessments is unknown.

Woodford Shale: The ICF assessment of 53 Tcf is the largest and was based upon ICF mapping and well production data. EIA assessed the formation at 15 Tcf and the Clean Skies report has 12

[34] American Clean Skies Foundation, 2008, "North American Natural Gas Supply Assessment," prepared by Navigant Consulting, July, 2008.
[35] EIA, 2008, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/oil_gas.pdf
[36] National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," NPC, Washington, D.C. http://www.npc.org

Table 15 Comparison of Current ICF and Other Published Lower-48 Shale Assessments

Tcf recoverable		**Current**		2008	2008		
		ICF	2002-08	Clean Skies	Clean Skies	2008	2003
Region	Basin	**Assessment**	USGS	Mean	Maximum	EIA	NPC
U.S.							
Appalachia							
	Appalachian Vertical Low Pressure	**30.6**	12.2	35.4	49.8	14.4	17.0
	Appalachian Marcellus Horizontal	**63.0**	not assessed	34.2	262.0	not assessed	not assessed
	Appalachian Huron Horizontal	**20.0**	not assessed	with vertical?	with vertical?	not assessed	not assessed
	total	**113.6**	12.2	69.6	311.8	14.4	17.0
Texas and LA							
Gulf Coast	Haynesville Shale	**31.0**	not assessed	34.0	251.0	not assessed	not assessed
Warrior Basin	Floyd and Conasauga Shales	**not assessed**	not assessed	2.1	4.5	not assessed	not assessed
Michigan-	MIchigan Antrim	**4.0**	7.47	13.2	20.0	10.6	7.4
Illinois	Illinois New Albany	**3.2**	3.79	3.8	19.2	2.0	1.8
	Cincinnati Arch	**2.3**	0.00			0.8	1.3
	total	**9.5**	11.26	17.0	39.2	13.3	10.4
North Texas							
	Fort Worth Barnett	**107.0**	26.20	26.2	44.0	38.0	7.0
Mid-Continent	Arkoma - Arkansas Fayetteville	**58.0**	not assessed	26.0	41.6	29.18	not assessed
	Arkoma - Oklahoma Woodford	**53.0**	not assessed	12.2	17.4	15.79	not assessed
	total	**111.0**	not assessed	38.2	59.0	44.97	not assessed
Permian Basin	Barnett and Woodford Horizontal	**10.0**	35.13	35.4	53.0	not assessed	not assessed
Williston	Williston Niobrara	**with tight**	not assessed	0.0		3.85	not assessed
	Williston Bakken Oil Play	**not assessed**	not assessed	1.8	3.0	not assessed	not assessed
Rockies	San Juan Lewis /1	**with tight**	not assessed	10.2	12.3	10.41	not assessed
	Denver Niobrara	**with tight**	not assessed	1.3	2.7	not assessed	not assessed
	Paradox Gothic Shale	**1.0**	not assessed	not assessed	not assessed	not assessed	not assessed
	Raton Basin Pierre	**2.0**	not assessed	not assessed	not assessed	not assessed	not assessed
	Green River Hilliard, Lewis, Mowry	**with tight**	not assessed	33.8	53.0	not assessed	not assessed
Pacific Onshore	San Joaquin Basin McClure	**0.32**	not assessed	not assessed	not assessed	not assessed	0.32
Other (Palo Duro Basin)		**0**	0	4.7	8.3	0	0.00
Lower 48 total		**385.4**	**84.8**	**274.3**	**841.8**	**125.0**	**34.7**
Alaska		not assessed	not assessed	not assessed	not assessed	not assessed	not assessed
U.S. total		**385.4**	**84.8**	**274.3**	**841.8**	**125.0**	**34.7**
Canada							
Eastern Canada	Quebec Area	**7.0**	not assessed	not assessed	not assessed	not assessed	not assessed
Alberta, Sas., Ma	Cretaceous Shale - Vertical	**9.4**	not assessed	not assessed	not assessed	not assessed	3.1
	Triassic Doig - Vertical	**8.4**	not assessed	not assessed	not assessed	not assessed	2.8
	Triassic Montney - Vertical	**11.2**	not assessed	not assessed	not assessed	not assessed	3.7
	Devonian Shale - Vertical	**22.6**	not assessed	not assessed	not assessed	not assessed	7.5
	Triassic Montney -Horizontal (part)	**2.0**	not assessed	not assessed	not assessed	not assessed	0.0
	total	**53.6**					17.2
British Columbia	Triassic Montney -Horizontal (part)	**10.0**	not assessed	not assessed	not assessed	not assessed	not assessed
	Devonian Shale - Horizontal	**60.0**	not assessed	not assessed	not assessed	not assessed	not assessed
	total	**70.0**					
Canada total		**130.6**					**17.2**

Tcf. We do not know the origin of the other studies. It may be that our mapped area of potential production is much larger than what is being assumed in the other reports. Our maps of potential Woodford production extend well beyond the areas of current activity.

Haynesville Shale: The ICF Haynesville assessment of 31 Tcf is similar to the Clean Skies mean estimate. The USGS has not assessed the formation. The ICF assessment is based upon preliminary volumetrics only, rather than a detailed mapping assessment. ICF does not have documentation of the origin of the Clean Skies maximum assessment of 251 Tcf

Permian Basin Barnett and Woodford: This play is known to have a tremendous amount of gas-in-place, but economic success has been very elusive. In recent years, there has been little reported about the play. It was assessed by the USGS in 2007 at 35 Tcf. However, activity to date over a number of years does not appear to support that assessment. ICF recently reduced our assessment of potential recovery to ten Tcf.

Appalachian Marcellus Shale: ICF has a preliminary assessment of 63 Tcf of potential recovery. As discussed above, the USGS gas-in-place volume was 295 Tcf. Based upon our mapping, we estimate a total unrisked gas-in-place of 350 Tcf over an area of 19,000 square miles. The 63 Tcf assessment results from the application of risk and recovery factors. The Clean Skies report has an assessment of 34 Tcf. The origin of that assessment is unknown.

Michigan and Illinois Basin Shales: The USGS has assessed the Antrim and New Albany shales on a vertical drilling basis. These results were published in the NPC study and there is not a great deal of difference in other recent assessments. The New Albany should probably be re-evaluated for horizontal potential.

5.7 Natural Gas Composition and Quality

The chemical composition of natural gas production from unconventional sources is a significant issue for industry. Future changes in the composition of produced gas in areas with emerging unconventional natural gas plays will have an impact on natural gas processing and transportation. There is variability in gas composition among plays and within individual plays. For example, gas "wetness" (defined below) can have a major impact on the need for liquids removal, and the presence of non-hydrocarbons such as carbon dioxide (CO_2) can require gas processing to remove the impurities. The impact of gas composition on pipeline infrastructure may be magnified by the large volume of gas production coming from one source that often has different composition than older, conventional sources in a basin, and from the rapid ramp-up of unconventional production.

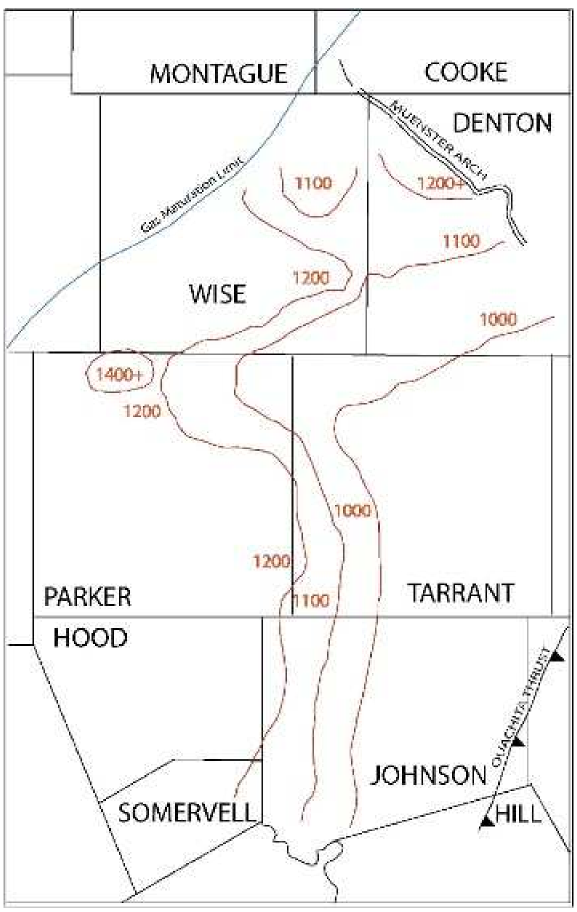
There is a paucity of data on the chemical composition of emerging unconventional natural gas plays. Research carried out by the Gas Research Institute in the 1990s to characterize U.S. natural gas composition at the wellhead was extensive, but focused on conventional reservoirs with limited information for coalbed methane and tight gas. An expansion of that work to encompass sampling of emerging natural gas resources, especially shale gas, is needed.

Natural gas production from the Barnett and other emerging shale tends to be "wet," meaning that the ratio of heavier components (C_2 or ethane and higher components such as propane and butane) to methane is high and the heating value is high. The CO_2 content in shale gas tends to be low. An exception is the Antrim Shale in the Michigan Basin -- the biogenic source of the methane produces CO_2 as well as methane. In contrast to shales, coalbed methane tends to be very dry (mostly methane), and may also have a significant fraction of CO_2, as in the San Juan Basin.

The composition of Barnett Shale production varies significantly in terms of natural gas wetness and liquid yield across the productive area. The play exhibits a gradation from dry gas to wet gas, to oil and gas. As shown in **Figure 23**, the heating content of Barnett Shale ranges from 1,000 to 1,400 Btus per cubic foot, with a general increase from east to west. This change in composition can be correlated with thermal maturity as measured by vitrinite reflectance. The term *thermal maturity* refers to the level of alteration of a source bed in the process of forming oil and gas through geologic time. *Vitrinite reflectance* is a specific measure of thermal maturity. A map of vitrinite reflectance is shown in **Figure 24**. (Note the different map scales). Areas of higher vitrinite reflectance in the eastern portion of the play are more thermally mature and have a dry gas with a lower heating content.

Figure 23 Map of Heating Content of Barnett Shale Gas

Source: Republic Energy [37]

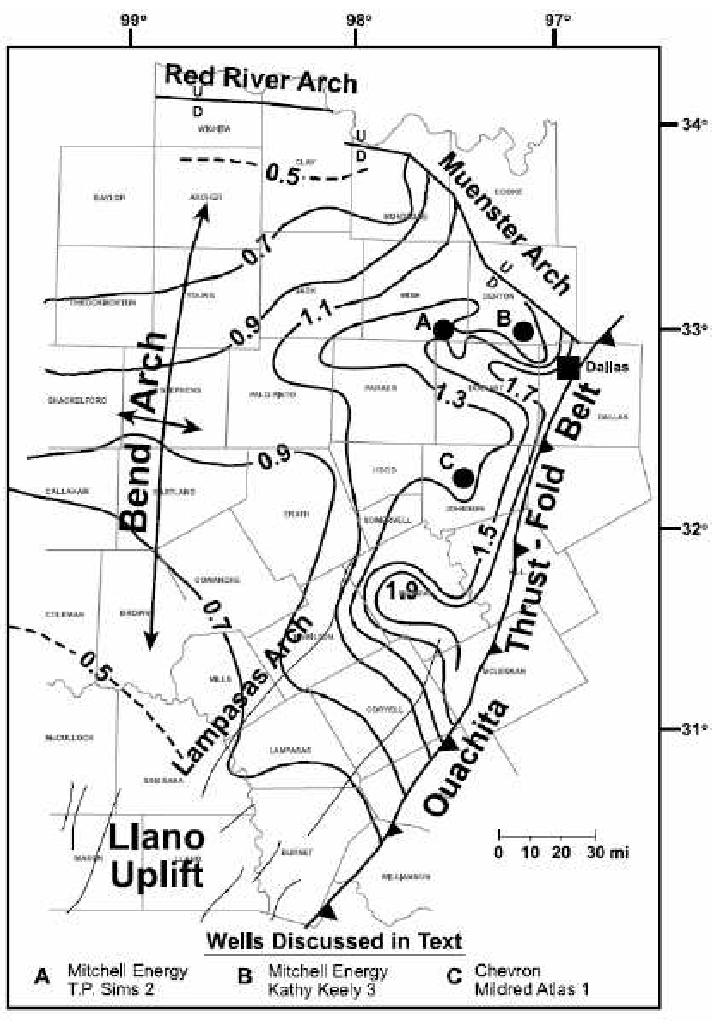


[37] Givens, Natalie, and Hank Zhao, 2004, "The Barnett Shale: Not so Simple After All," Republic Energy, Dallas, TX https://www.republicenergy.com/Articles/Barnett_Shale/Barnett.aspx

Both the overall wetness of the Barnett and the lateral variability of wetness are significant in terms of natural gas processing infrastructure needs. This is because the liquids must be stripped from the gas before they can be accepted for long distance transport by transmission pipelines. Where existing gas processing capacity is not adequate, development of the gas resource may be restricted. Natural gas processing and liquids infrastructure must be developed in coordination with overall gas gathering and transportation.

Figure 24 Barnett Shale Thermal Maturation (Vitrinite Reflectance)

Source: "The Barnett Shale" (Pickering Energy Partners) [38]



[38] Pickering Energy Partners, 2005, "The Barnett Shale," http://www.pickeringenergy.com

6 REGIONAL TIGHT GAS, SHALE GAS, AND COALBED METHANE PRODUCTION AND ACTIVITY

6.1 Introduction

This chapter presents information on activity and potential of individual plays and basins. Many of the major unconventional plays are presented. Production and activity is evaluated in terms of each major producing region and within producing basins. For the largest plays and for emerging shale plays, information is presented on which companies are active, what the companies have stated about the potential for the play, and play economics.

6.2 Characteristics of Major Plays

The potential for a given play to produce gas is dependent upon a wide range of geological, geochemical, and physical properties. Generally speaking, the key characteristics are known. For shale gas, they include thickness, depth, organic content, and vitrinite reflectance or thermal maturity. Other important factors that are now known to be important include silica content, clay content, and pressure gradient. Some productive shale gas, such as the Antrim Shale, is biogenic in origin (methane sourced from bacteria), rather than thermogenic (methane sourced from conversion of organic material through heat and pressure). A summary of published characteristics for major shale plays is shown in **Table 16**.

For coalbed methane, important considerations are thickness, coal rank (bituminous, sub-bituminous), depth, distribution of seams, CO_2 content, water saturation and need for dewatering, biogenic vs thermogenic methane, and other factors. A summary is shown in **Table 17**.

Table 16 Characteristics of Major Shale Plays

Sources: Published reports and gas industry slides

		Ft. Worth Barnett Non-Core Horizontal	Arkoma Fayetteville Horizontal	Arkoma Woodford Horizontal	Michigan Antrim Vertical	Illinois New Albany	Permian Woodford Vertical	Appalachian Marcellus Vertical	Appalachian Huron	Louisiana Haynesville Horizontal	Warrior Floyd Vertical
Geologic Age		Devonian	Devonian	Mississippian	Devonian	Devonian	Devonian	Devonian	Devonian	Jurassic	Mississippian
Vertical Depth	ft	4,500 - 9,000	1,500 - 6,500	6,000 - 12,000	600 - 2,400	3000	8,000 - 12,000	5,000 - 8,500	3,500 - 5,500	10,000 - 13,000	6,500 - 9,000
Gross Thickness	ft	200 - 800	50 - 400	100 - 300	150	100 - 300	400 - 800	50 - 200	150 - 200	200+	100 - 300
Pressure Gradient	psi/ft	.45 - .50	0.44			0.43				0.5 - 0.7?	
Origin of gas		Thermogenic	Thermogenic	Thermogenic	Biogenic	Thermogenic	Thermogenic	Thermogenic	Thermogenic	Thermogenic	Thermogenic
Total Organic Carbon	%	3.5 - 5.0+	2.0 - 5.0+	3.0 - 10.0	0.3 - 20+	1 - 25	4.0 - 7.0	2.0 - 6.0	3.5	3.0 - 5.0	1.8 (0.5- 10)
Vitrinite Reflectance	%Ro	1.0 - 2.2	1.5 - 4.0	1.1 - 3.0	0.4 - 0.6	<0.7		1.0 - 2.5			0.92 - 1.6
Silica Content	%	40-60	40-60	60-80							
Gas Content	scf/ton	300 - 500			40 - 100						
Gas-in-place/sq. mile	Bcf/sq. mi.	50-250	30-80	35-130	6 - 15		100-500			150-250	
Reserves per well	MMcf	1,500-3,000 +	1,600 +	3,000 - 5,000	200 - 600		3,000	800 (vert.)	800 - 1,500	3,000 - 6,500	
General gas wetness		Wet		Wet		Wet		Wet			Dry
CO2	%				Up to 20%	0 - 5 %					negl.
Methane	%							80 - 95			
Heating Content	Btu/cf	1,000 - 1,400						900 - 1,300			
Current Wells		7,500	600 +	500 +	8,300 +						

		E. Canada Utica Horizontal	BC Muskwa Horizontal	BC Montney Horizontal
Geologic Age		Ordovician	Devonian	Triassic
Vertical Depth	ft	2,300 - 6,000	7,800 - 13,000	6,500 - 12,000
Gross Thickness	ft	500	500	500
Pressure Gradient	psi/ft	.45 - .60		
Origin of gas		Thermogenic	Thermogenic	Thermogenic
Total Organic Carbon	%	1.0 - 3.1	3.0	1.5 - 6.0
Vitrinite Reflectance	%Ro	1.3 - 3.0	2.8	0.8 - 2.5
Silica Content	%		65	
Gas Content	scf/ton			
Gas-in-place/sq. mile	Bcf/sq. mi.	75 - 350	180 - 320	75 - 100
Reserves per well	MMcf	1,700	4,000+	2000+
General gas wetness				
CO2	%	none		
Methane	%	88 - 97		
Heating Content	Btu/cf	1,027 - 1,136		
Current Wells				

Table 17 Characteristics of Major Coalbed Plays

Source: Adapted from Jenkins, C.D. and Charles M. Boyer, Journal of Petroleum Technology, Feb. 2008

		San Juan		Uinta	Raton	Warrior	Powder River	WCSB
Formation		Fruitland	Fruitland	Ferron	Vermejo	Pottsville	Wyodak	Horseshoe Canyon
Well type		Vertical	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical
Sub-basin area		Fairway	Non-Fairway					
Net coal thickness	ft	70	20 - 40	4 - 48		25 - 30	40 - 300	35 -110
Depth					2,500 - 5,500		250 - 1,500	
Rank		Bitum.	Bitum.	Bitum.		Bitum.	Sub-bitum.	Sub-bitum.
Gas Content	scf/ton	300 - 600		425		250 - 500	30 - 70	35 - 110
Well spacing	acres	60 - 320		160		80	80	80 - 160
Rate per well	mcf/d	1,500		500		100	150	45
Recovery factor	%	66		57		53	62	28
Reserves per well	Bcf	6.00	0.50	1.5 - 4.0		0.5 - 1.5	0.2 - 0.5	0.25 - 0.5
Pressure regime		High	Low				Low	
Completion method		Cavitation	Frac.				Open hole	
Significant CO2		Yes	Yes					
Producing wells	basin total	> 3,600		>580	>1,100		17,000	9,300

6.3 Activity Summaries and Discussion of Existing and Emerging Plays

North America Play Level Production

Production and completion activity have been evaluated for most of the major unconventional natural gas plays in North America. The results of this analysis are summarized **Table 18**. The table summarizes tight gas, coalbed methane, and shale gas production by basin. Production for individual plays is discussed below. For tight gas, the plays shown represent most of the tight gas production in the U.S. An estimate was made of the amount of tight production from other plays. Total unconventional natural gas production in 2007 was approximately 9.1 Tcf or 48 percent of total dry U.S. natural gas production.

Rockies

Natural gas production in the Rockies has been increasing rapidly in recent years, and the growth is attributed to tight gas. **Figure 25** shows the state level total gas production from 1990, including both conventional and unconventional natural gas production. **Table 19** shows play level production. **Figure 26** shows the significance of unconventional natural gas in the region.

Since 1990, production in the Rockies has more than doubled. The chart shows that production growth since 2000 was primarily in Colorado and Wyoming. This is due to tight gas in the Green River and Piceance Basins. In the 1990s, New Mexico experienced increased production from coalbed methane in the San Juan Basin. Natural gas production in Utah was constant through 2006, but is now increasing due to tight gas development. Montana production is gradually increasing, due in part to coalbed methane in the state's portion of the Powder River Basin.

Jonah-Pinedale Tight Gas

Jonah and Pinedale natural gas fields in the Green River Basin of southwestern Wyoming have been the location of an intense tight gas development effort over the past decade. ICF's database indicates annual production from both fields of 717 Bcf in 2007 or about 2 Bcf per day. Production from both fields increased greatly during 2007, from an average of about 1.6 Bcfd in 2006 to 2.0 Bcfd in 2007.

Geologically, the fields are characterized by a very thick section (6,000 feet) of low permeability Lance formation sands interbedded with shales. Within the overall gross interval are 20 to 70 individual sands with a net pay averaging 1,400 feet. [39] [40] Depth of production ranges from 7,000 to 14,000 feet and wells are drilled vertically/directionally from surface pads. Horizontal drilling is not required because of the thickness of the overall interval and the success of vertical well stimulation procedures that have been developed.

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[39] Oil and Gas Journal, August 3, 2007.
[40] Oil and Gas Journal, March 3, 2008.

Table 18 North American Basin Level Unconventional Natural Gas Production

Tight Gas Analysis Consists of Studied Plays and Estimates for Other Tight Production
Coalbed Methane and Shale Gas Defined by Play is U.S. Total

BCF per Year Raw Gas

Region	Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	Percent Change Since 2000
North Texas	Fort Worth Basin	Shale	79	135	221	305	381	504	707	930	1077%
Mid-Continent	Arkoma	Shale	0	0	0	0	3	16	44	160	na
Mid-Continent	Chautaqua	CBM	11	16	21	26	28	28	28	28	155%
Mid-Continent	Cherokee	CBM	2	3	4	9	13	16	22	30	1329%
Mid-Continent	Anadarko	Tight	83	91	97	101	141	182	231	260	213%
East Texas	East Texas	Tight	540	619	646	725	826	962	1,065	1,176	118%
West Texas	Permian	Tight	310	342	332	315	312	334	340	360	16%
Rockies	Powder River	CBM	161	264	336	353	337	320	376	429	166%
Rockies	Green River	Tight	138	187	263	332	387	504	580	717	419%
Rockies	Green River	CBM	0	0	1	3	4	5	6	7	na
Rockies	Piceance	Tight	65	83	112	144	203	256	313	336	419%
Rockies	Piceance	CBM	1	1	1	3	3	2	2	2	162%
Rockies	Uinta	Tight	68	69	73	79	97	125	160	178	162%
Rockies	Uinta	CBM	76	93	103	99	91	84	79	79	4%
Rockies	Raton	CBM	45	49	74	87	91	99	114	123	173%
Rockies	Denver	Tight	136	156	176	191	188	180	177	180	32%
Rockies	San Juan	Tight	454	461	462	461	455	447	450	452	0%
Rockies	San Juan	CBM	966	918	900	904	912	907	889	840	-13%
Western Gulf Coast	Texas Gulf Coast	Tight	460	434	416	419	423	415	432	445	-3%
Eastern Gulf Coast	Warrior	CBM	109	111	117	110	121	113	114	115	6%
Appalachian	Virginia	CBM	53	54	59	63	67	69	81	90	70%
Appalachian	PA and WV	CBM	10	15	15	15	26	21	24	25	150%
Appalachian	Appalachian	Tight	300	300	300	300	350	350	350	350	17%
Appalachian	Appalachian	Shale	200	180	170	160	150	150	150	150	-25%
Midwest	Michigan	Shale	183	175	166	154	149	144	141	136	-26%
Western Canada	Alberta	CBM	2	5	4	4	23	47	167	237	12900%
U.S. Tight Gas- Defined Plays Above			2,554	2,742	2,877	3,066	3,382	3,756	4,098	4,454	74%
U.S. Tight Gas- Estimate for Other Plays			1,015	1,069	1,033	1,085	1,142	1,161	1,322	1,468	45%
U.S. Tight - Estimated Total			**3,569**	**3,811**	**3,910**	**4,151**	**4,524**	**4,917**	**5,420**	**5,922**	66%
U.S. Coalbed			**1,292**	**1,336**	**1,424**	**1,462**	**1,516**	**1,517**	**1,627**	**1,649**	28%
U.S. Shale Gas			**371**	**430**	**502**	**593**	**685**	**818**	**1,098**	**1,538**	315%
U.S. Unconventional			**5,232**	**5,577**	**5,836**	**6,206**	**6,725**	**7,252**	**8,145**	**9,109**	
U.S. dry gas production			**17,989**	**19,318**	**18,893**	**18,947**	**18,690**	**17,940**	**18,137**	***18,860***	5%
Percentage of Production That is Unconventional											
Percent tight (estimated total tight)			**19.8%**	**19.7%**	**20.7%**	**21.9%**	**24.2%**	**27.4%**	**29.9%**	**31.4%**	
Percent coalbed			**7.2%**	**6.9%**	**7.5%**	**7.7%**	**8.1%**	**8.5%**	**9.0%**	**8.7%**	
Percent shale			**2.1%**	**2.2%**	**2.7%**	**3.1%**	**3.7%**	**4.6%**	**6.1%**	**8.2%**	
Percent unconventional			**29.1%**	**28.9%**	**30.9%**	**32.8%**	**36.0%**	**40.4%**	**44.9%**	**48.3%**	

Figure 25 Rocky Mountain State Gas Production Trends

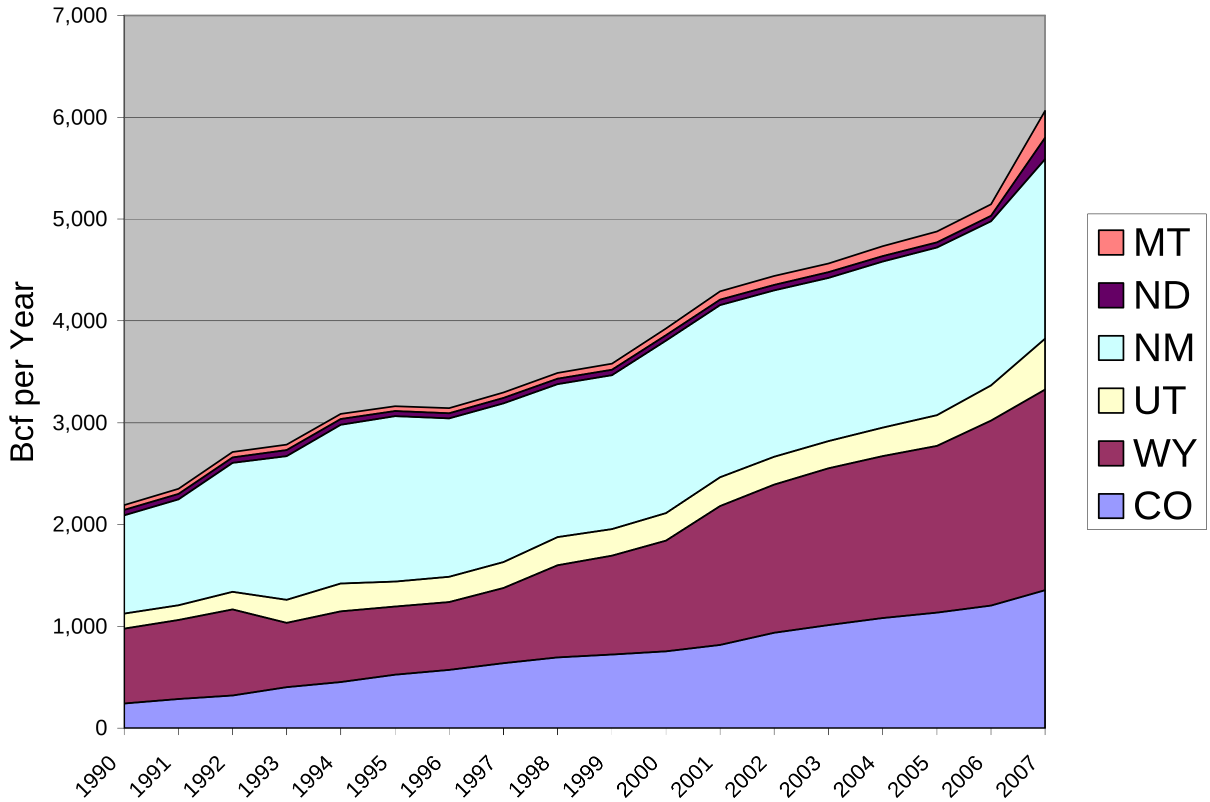
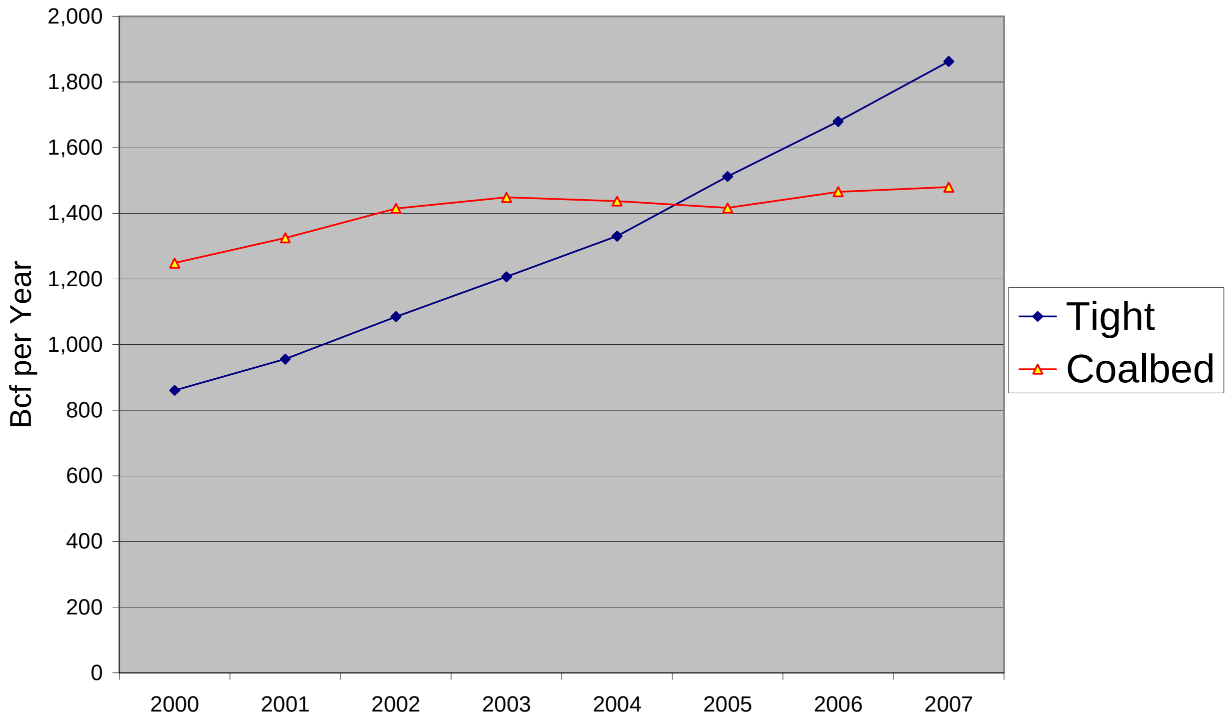


Table 19 Rockies Unconventional Natural Gas Production by Play

BCF per Year Raw Gas

Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	Percent Change Since 2000
Powder River	CBM	161	264	336	353	337	320	376	429	166%
Green River	Jonah Pinedale Tight	138	187	263	332	387	504	580	717	419%
Green River	CBM	0	0	1	3	4	5	6	7	na
Piceance	Mesaverde Tight	65	83	112	144	203	256	313	336	419%
Piceance	CBM	1	1	1	3	3	2	2	2	162%
Uinta	Natural Buttes Tight	68	69	73	79	97	125	160	178	162%
Uinta	Ferron CBM	76	93	103	99	91	84	79	79	4%
Raton	Vermejo CBM	45	49	74	87	91	99	114	123	173%
Denver	Wattenberg Tight	136	156	176	191	188	180	177	180	32%
San Juan	Dakota Tight	138	137	137	140	139	137	140	142	3%
San Juan	Mesaverde Tight	316	324	325	321	316	310	310	310	-2%
San Juan	Fruitland CBM	966	918	900	904	912	907	889	840	-13%
Tight Total - Studied Plays		861	956	1,086	1,206	1,330	1,513	1,680	1,863	116%
Coalbed Total		1,249	1,325	1,415	1,449	1,438	1,417	1,466	1,480	19%
Shale Total - Studied Plays		0	0	0	0	0	0	0	0	
Total Unconventional		2,110	2,281	2,501	2,655	2,768	2,930	3,146	3,343	58%

Figure 26 Rockies Unconventional Natural Gas Production Summary



Major operators at Jonah-Pinedale include Ultra Petroleum, Questar, Shell, BP and Encana. Encana and BP have the largest positions at Jonah, whereas Ultra is the largest operator at Pinedale. Ultra Petroleum indicates that Pinedale has 750 natural gas wells and Jonah has about 1,000 wells. [41] These numbers are consistent with ICF's tight gas well database. The field-wide average production is 1.1 MMcf per day per well. Ultra states that they have about 5,300 drillsites in their inventory. Further, ultimately recoverable resources are 31 Tcf from Pinedale and 8.5 Tcf from Jonah.

Ultra's recent drilling has indicated *estimated ultimate recovery* (EUR) per well of 6.5 Bcf and a cost to drill and complete the vertical well of $6.2 million. (EUR is a measure of how much gas a well is expected to recover in its lifetime). In 2007, they completed 183 wells averaging 8.8 MMcfd each. One recent well at Pinedale produced 11.9 MMcf per day and has an EUR of 8.6 Bcf. [42]

Of the total well cost, a large percentage is from the fracturing jobs to stimulate production. Each fracturing stage costs $100,000 and there are about 20 stages in one well, totaling $2 million per

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[41] Ultra Petroleum, April, 2008 investor slides.
[42] Oil and Gas Journal. March 3, 2008.

well just for the stimulation. That can be compared to the average cost of $6.2 million reported above, indicating that the fracturing component of the costs is about one-third of the total. [43]

Piceance Basin Tight Gas

The Piceance Basin of northwestern Colorado has been the location of intense tight gas sand development for many years. Operators include Williams, Encana, ExxonMobil, and XTO. The basin produced 446 Bcf of gas well gas in 2007, or an average of 1.2 Bcfd. This can be compared to 403 Bcf or 1.1 Bcfd in 2006. In 2000, basin production was only 288 MMcf per day.

Tight gas activity is focused on the Williams Fork interval of the Mesaverde Group at depths ranging from 4,500 to 8,500 feet. One of the main areas of development is a group of four fields: Grand Valley, Parachute, Rulison, and Mamm Creek. In 2007, these fields produced about 900 MMcf per day representing most of the basin production.

In an August, 2007 presentation, XTO estimated that they have two to four Tcf of potential in the basin. They indicated that natural gas-in-place per square mile is approximately 400 Bcf. Production is from a 4,000 foot gross formation thickness averaging 850 to 1,000 feet of pay. (Pay is the net interval thickness that is expected to produce). Well costs are $9 to $10 million and wells are recovering three to six Bcf. [44] If one assumes an average of four Bcf per well and three Tcf of potential, this would represent 750 future wells.

Bill Barrett Corporation has published some information on their Piceance wells. In their Gibson Gulch area, there is an average potential production of 1.0 Bcf per well with a total completed well cost of $1.9 million. [45] The well cost includes $0.8 million for drilling and $1.1 million for completion. Finding and development costs are $2.06.

Williams is using a "FlexRig" system to improve efficiency. The rig has the capability of drilling up to 22 wells from a single pad, using directional wells. [46] The company cites large remaining potential in the Piceance Valley, as well as the Piceance Highlands. The Highlands area is said to have three Tcf of potential in 3,700 locations. Recently completed wells are averaging 1.2 to 2.4 Bcf per well.

Uinta Basin Natural Buttes Tight Gas

The Uinta Basin of northeastern Utah produced 350 Bcf of non-associated natural gas in 2007. This was double the amount of gas produced in 2000 (172 Bcf). Essentially all of the production growth has been in the Mesaverde and Wasatch tight gas plays. The giant Natural Buttes field is the focus of much of the activity. This field and the adjacent Monument Butte field contain thousands of feet of natural gas productive intervals. Natural gas reserves are being developed on 20 and 10 acre well spacing. The fields were developed previously on 40 acre spacing.

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[43] Oil and Gas Journal, March 3, 2008.
[44] XTO, March, 2008 Investor slides.
[45] Bill Barrett Corporation, March, 2008 investor slides.
[46] Williams, February, 2008 investor slides.

At Monument Butte, Newfield is developing oil in the shallow intervals. This area has a very large deep interval with natural gas potential that is being evaluated. The deep interval consists of Wasatch, Mesaverde, Blackhawk, and Mancos Shale formations ranging to depths of 16,000 feet.

EOG Resources is one of the main operators in the basin. They are developing tight gas resources in the Mesaverde and Wasatch formation. They are drilling on 40s, 20s, and 10 acre spacings. The completed wells for Wasatch cost $1.2 million and they recover 0.7 Bcf. Mesaverde wells cost $1.65 million and recover 1.2 Bcf. [47] EOG states that the gas-in-place resource averages 250 Bcf per square mile in the basin.

Bill Barrett is developing an area of the Uinta Basin called West Tavaputz. They are drilling both Wasatch and Mesaverde at relatively shallow depths of less than 8,000 feet. EUR per well is 2.5 Bcf and completed well costs are $3.1 million. This consists of $1.0 million for drilling and $2.1 for stimulation/completion. [48] Finding and Development (F&D) costs are $1.26 per mcf. They also mention a deep natural gas play consisting of Navajo, Entrada, Dakota, and Mancos Shale.

Powder River Basin Coalbed Methane

The Powder River Basin is located in northeastern Wyoming and southeastern Montana. Through the early 1990s it had a history of conventional oil and natural gas production. Beginning in the mid-1990s, significant activity and production started in the coalbed methane play. Production in the basin (including conventional natural gas) has grown from about 860 MMcfd in 2001 to a 2007 rate of 1.3 Bcfd. Most of the production growth occurred by 2001. Since that time, production has been relatively flat, although production was up slightly in 2007. Of the total basin production in 2007 of 1.3 Bcfd, 1.2 Bcfd was coalbed methane.

Initially, activity primarily involved the shallow Tertiary Fort Union Wyodak coals on the eastern flank of the basin. Wells are shallow, about 800 - 1,500 feet in depth, and typically produce around 250 to 300 MMcf over the life of the well. While basin production remains dominated by the shallow Wyodak play, over the past few years the deeper Big George coalbed formation has become increasingly important in terms of both activity and production. Well recoveries are higher in the Big George than in the Wyodak, and in some areas, recoveries are 600 MMcf per well or higher.

Bill Barrett is active in the Big George play. In a recent presentation, they indicated a range of EUR per well for the formation of 0.15 to 0.8 Bcf with a typical value of 0.3 Bcf. [49] Drilling and completion (D&C) cost is some $220 thousand which includes $90 thousand for drilling and $130 thousand for completion and equipment. This equates to an incremental D&C cost of $0.88. The play is generally to the west of the original Wyodak play and covers an area of about 4 X 10 = 40 townships or 1,400 square miles.

Green River Basin Coalbed Methane

The Green River Basin of southwestern Wyoming only produces about 20 MMcf per day of coalbed methane. However, production has been increasing gradually. It appears that the play may experience significant growth over the next few years. In 2007, the BLM issued a Record of

[47] EOG, February, 2008 investor slides.
[48] Bill Barrett, March, 2008 investor slides.
[49] Bill Barrett, April, 2008 investor slides.

Decision allowing the Atlantic Rim Coalbed project to proceed. [50] The decision will allow the completion of 1,800 coalbed methane wells, most of which will be completed over the next five years. [51] An Anadarko publication states that they plan to complete 160 CBM wells in the field in 2008. Double Eagle Petroleum is working with Anadarko Basin on the project. They indicate that initial potentials from very recent wells drilled during the past year have increased substantially, with recent wells averaging 783 mcf per day. [52] Wells are expected to recover 0.9 to 1.2 Bcf with a drilling and completion cost of $1.1 million including infrastructure.

Baxter Shale – Green River Basin

Two firms – Questar and Kodiak Oil and Gas– have been testing the potential for natural gas production from the Cretaceous Baxter Shale in the southern Green River Basin in Wyoming and Colorado. The Baxter is at depths of 9,500 to 13,000 feet and there are deeper tight sands objectives in the Dakota and Frontier. [53] Questar has completed approximately 20 wells, although very little information is available on them. Kodiak is said to have tested 2 MMcfd in the Kodiak in a $4.5 million well with 9 frac stages. [54]

Pierre Shale - Raton Basin, Colorado

Pioneer Natural Resources has discovered a large volume of recoverable gas in the Pierre Shale of the Raton Basin in Colorado. This play lies beneath its existing coalbed methane production. The play is said to encompass 134,000 acres, all held by production from the coalbed methane. Pioneer has drilled five vertical wells which are producing a combined 2 MMcf per day. [55] The company plans 15 Pierre wells in 2008, and indicates that there are 1,200 risk-adjusted well locations on 80 acre spacing. (Companies often cite risk-adjusted locations, which adjusts gross drilling locations for perceived geological risk factors). They expect 70 Bcf of proved reserves by year end 2008 and 200 Bcf by 2010, and are also testing horizontal completions.

Gothic Shale – Paradox Basin, Colorado

Bill Barrett has tested natural gas from the Gothic Shale formation in the southwestern Colorado portion of the Paradox Basin. A 2007 well in Montezuma County, Colorado tested at 500 mcfd with a gas heating value of 1,200 Btu. [56] A recent company report states that they are evaluating the play and plan one or two horizontal wells in 2008. The shale section is about 150 feet thick, thermally mature, and overpressured. The depth range is 5,500 to 7,500 feet. It has been reported that Barrett expects 800 Bcf equivalent of potential and is anticipated one to three Bcf per well. [57]

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[50] Bureau of Land Management, 2007, "Record of Decision – Environmental Impact Statement for the Atlantic Rim Natural Gas Field, Carbon County Wyoming" BLM, Cheyenne, Wyoming, March, 2007.
[51] Oil and Gas Journal, September 24, 2007.
[52] Double Eagle Petroleum, April, 2008 investor slides.
[53] Questar 2007 Annual Report.
[54] Oil and Gas Journal, August 3, 2007.
[55] Oil and Gas Journal, April 9, 2008.
[56] IHS, 2007, Industry Highlights, May, 2007.
[57] Oil and Gas Journal, September 24, 2007.

Mid-Continent

Figure 27 shows the state level natural gas production trend for the Mid-Continent region. Production had been in a steady decline until recent years but has now turned the corner due to tight gas and shale gas development. **Table 20** and **Figure 28** present the play level data and a summary of unconventional natural gas production.

Figure 27 Mid-Continent State Natural Gas Production Trends

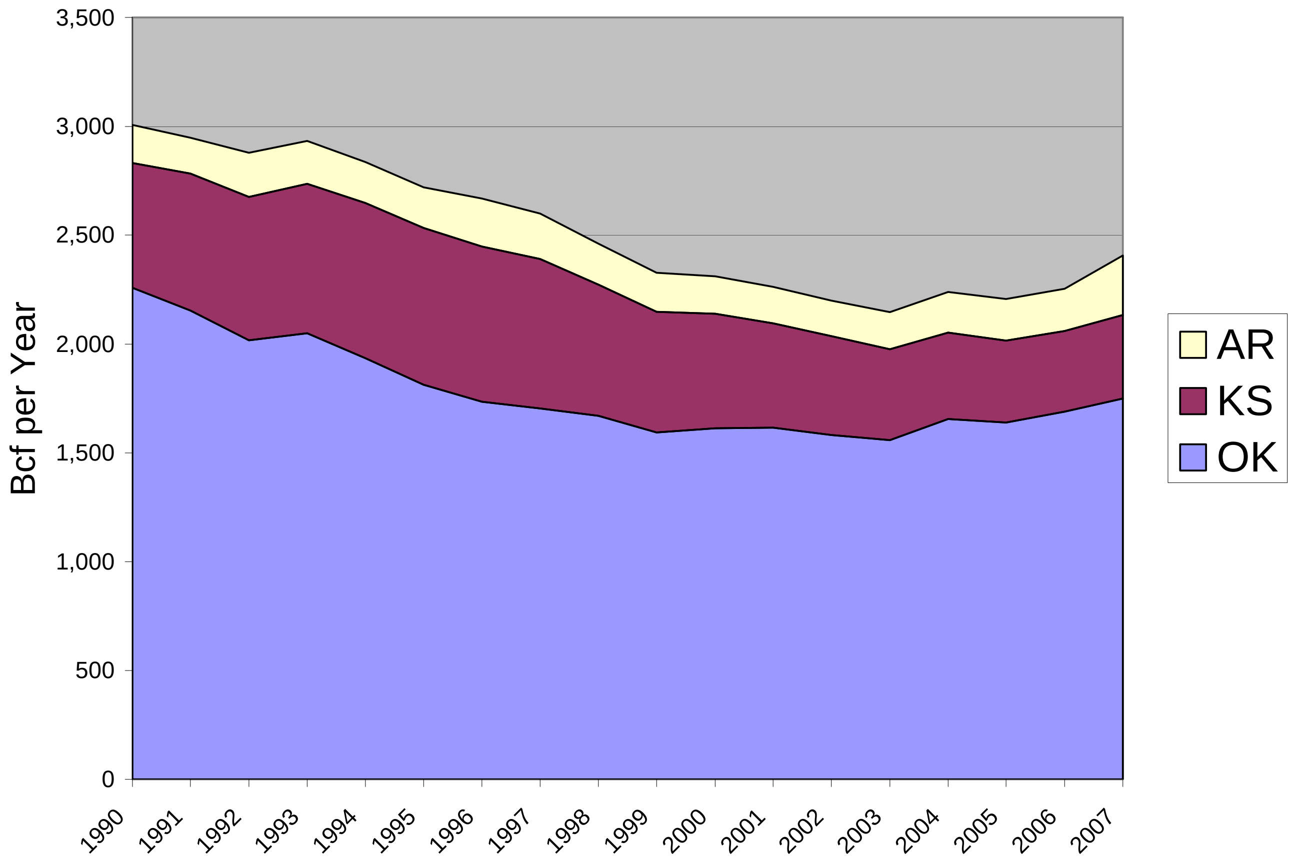
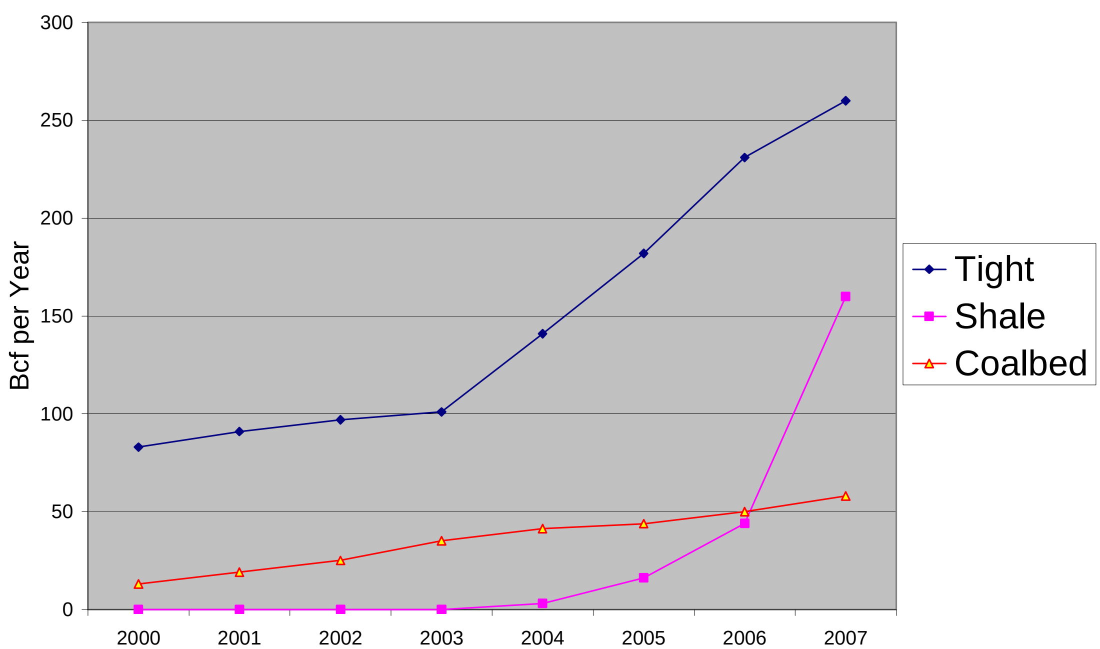


Table 20 Mid-Continent Unconventional Natural Gas Production by Play

BCF per Year Raw Gas										Percent Change Since
Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	2000
Arkoma	Woodford Shale	0	0	0	0	3	14	29	71	na
	Fayetteville Shale	0	0	0	0	0	2	15	89	na
Chautaqua	Hartshorne CBM	6	9	12	15	15	15	15	15	150%
	Cherokee CBM	5	7	9	11	13	13	13	13	160%
Cherokee	Cherokee CBM	2	3	4	9	13	16	22	30	1329%
Anadarko	Cleveland Tight	32	32	32	35	46	55	59	60	88%
	Granite Wash Tight	51	59	65	66	95	127	172	200	292%
Tight Total - Studied Plays		83	91	97	101	141	182	231	260	213%
Coalbed Total		13	19	25	35	41	44	50	58	343%
Shale Total - Studied Plays		0	0	0	0	3	16	44	160	na
Total Unconventional		96	110	122	136	186	242	325	478	397%

Figure 28 Mid-Continent Unconventional Natural Gas Production Summary



Fayetteville Shale – Arkoma Basin

The most active operator in the Fayetteville Shale horizontal drilling play in the Arkansas Arkoma Basin is Southwestern Energy. Southwestern Energy has an acreage position of about 850,000 acres and has gross operated production of about 400 MMcfd. [58] The company continues to have excellent success across a wide geographic area. They have drilled a total of 533 wells, including 426 horizontals completed with slick water fractures. The average lateral length has increased to 3,300 feet and current completed well costs are averaging $3.05 million. The average recovery of recently drilled wells appears to be more than 1.5 Bcf based on company published production information and charts.

Southwestern Energy has 33 pilot tests encompassing areas of 8 counties in Arkansas. Their pilot and development activity is about 140 miles east-west while the north-south dimension is about 30 miles for an area of about 4,200 square miles. This compares to ICF's mapped assessment of the Fayetteville (which includes the entire play, not just the Southwestern Energy part) of about 9,000 square miles. One recent article indicated that the eastern portion of the play, termed the Mississippi Embayment area, is not performing as well as the core area. [59]

Geologically, the play is the same age as the Barnett Shale, but there are many differences. There is more lateral geological variability overall than the Barnett. In the Fayetteville, the thickest portion of the shale lies in the shallower areas, while in the Barnett the thickest shale lies in the deeper areas. [60] Despite this, there appears to be a very broad area of anticipated economic development.

Other operators include Chesapeake, XTO, and Petrohawk. Petrohawk is reporting the potential for one to four Bcf per well with completed well costs of $1.75 to $2.75 million. There is a total of 9,900 potential locations and 3.2 Tcf of potential on their leasehold. [61] Well depths range from 1,500 feet in the northern shallow part of the play to 5,500 feet in the southern area. The $2.7 million well cost relates to the 5,500 foot wells.

Woodford Shale – Arkoma Basin

The Devonian Woodford Shale horizontal play in the eastern Oklahoma portion of the Arkoma Basin continues to be very active. ICF analysis indicates that the play produced approximately 71 Bcf in 2007 for an average rate of almost 200 MMcfd. The production rate as of January was reported by operators to be 275 MMcfd.

The most active operator is Newfield Exploration, with a reported year end production rate of 160 MMcfd and a forecast 2008 exit rate of 260 MMcfd. [62] Reported total industry drilling was 444 wells through 2007 with Newfield accounting for about 160. Other operators include Devon, Antero, Chesapeake, Continental Resources, Petroquest, and XTO.

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[58] Southwestern Energy, May 2008 investor slides.
[59] Oil and Gas Investor, 2007, "An Investor's Guide to Shale Gas," January, 2007.
[60] Oil and Gas Investor, 2007, ibid.
[61] Petrohawk, May, 2008 investor slides.
[62] Newfield Exploration, March, 2008 investor slides.

Well completion methods and approaches continue to evolve in the Woodford. Newfield has developed approaches that are recovering more natural gas and getting much higher initial well productivity. Recent success with this effort has resulted from longer laterals and more fractures per well. [63] [64]

Newfield has drilled 66 standard laterals at a standard length of 2,500 feet. They have drilled 14 extended laterals longer than 3,000 feet. [65] Current F&D costs are reported to be approximately $2.30 - $ 2.40 per mcf, but the firm believes that increased drilling of extended laterals to 3,500 – 4,700 feet or more will reduce costs to a range of $2.00 or less. Cost saving approaches that are also being applied include drilling up to four wells per pad and performing simultaneous fractures in adjacent wells. Vertical well depths are in the range of 8,000 to 11,000 feet.

The Woodford covers a very large area and exhibits large geologic variability. Because of this, Newfield is now using 3-D seismic surveying before drilling in most cases. The play does not apparently have the karsting (erosional) issues that occur in the Barnett, which has presented difficulties in that play. However, there are faults in the play. Faults with significant offset (vertical displacement) can make it difficult to keep within the targeted interval in the horizontal section.

Granite Wash Play – Anadarko Basin

The ICF database indicates that the Granite Wash tight gas play in the western Anadarko Basin produces about 200 Bcf per year from 2,500 natural gas wells.

Chesapeake Energy has been very active in an area called the Colony Granite Wash play in Custer and Washita Counties, Oklahoma. Recently, they announced that they are teaming with Enogex to expand gathering and processing in the play. They indicate the potential for 650 wells averaging 3.2 Bcf each for an undeveloped potential of about 2.1 Tcf. [66] The companies are running 12 rigs in the play.

The Granite Wash play is also active in the Texas Panhandle. Questar reports that they have 235 drilling locations in the Texas part of the play. The EUR per well is 0.8 to 2.0 Bcf and drilling costs are $2.2 to $4.4 million.

Atoka Play – Western Anadarko

Pennsylvanian Atoka tight sands are being targeted in the Texas Panhandle. EOG Resources is active in Atoka horizontal drilling, with 17 wells drilled to date. [67] They report initial well potential rates in the range of six to seven MMcfd with completed well costs of $3.4 million and 400 Bcf of play potential.

[63] Oil and Gas Investor, 2007, "An Investor's Guide to Shale Gas," January, 2007.
[64] Oil and Gas Journal, April 7, 2008.
[65] Oil and Gas Journal, April 7, 2008.
[66] Chesapeake Energy, May, 2008 investor slides.
[67] EOG, May, 2008 investor slides.

Cleveland Sand Horizontal Play – Anadarko Basin

The Cleveland tight sand play in the northeast corner of the Texas Panhandle and extending into western Oklahoma has been active for several decades with vertical drilling and stimulation. Over the past ten years, horizontal development has dominated. BP tested horizontal laterals using slim hole drilling. It has been reported that over 350 horizontal wells have been drilled in the play, with recoveries averaging 1.5 Bcf per well. [68] In addition, it has been reported that 20 horizontals were completed in in 2003, followed by annual totals of 70, 90, and 115 in 2006. [69] The depth range of the play is relatively shallow, at about 6,500 to 8,000 feet. EOG Resources and Jones Energy have been active in the play.

Woodford Shale Gas in the Anadarko Basin

Cimarex Energy announced the emergence of a horizontal drilling natural gas play in the Woodford Shale of the Anadarko Basin. [70] Measured drilling depth is in the range of 13,000 to 15,000 feet and lateral lengths being tested range from 2,500 to 4,000 feet. One well in Canadian County flowed 2.6 MMcfd and 61 b/d of oil.

North and East Texas

The geological basins in North and East Texas are the location of some of the most active development of unconventional natural gas resources in North America. Included here is the Barnett Shale of the Fort Worth Basin and the Bossier and Cotton Valley tight sands in East Texas. **Figure 29** is a chart showing district level natural gas production trends since 1990. Texas Railroad Commission districts 5 and 6 cover the northeast corner of the state and are generally equivalent to the geological East Texas Basin. District 9 and 7B encompasses most of the Barnett Shale play in the Fort Worth Basin. The chart shows rapid growth over the past decade concentrated in District 5 and 9. The District 5 growth is attributed mostly to the Bossier tight sand play while District 9 growth is largely from the Barnett Shale.

Table 21 and **Figure 30** show the trends in unconventional natural gas. Barnett Shale production increased from 79 Bcf in 2000 to 930 Bcf in 2007 and continues to increase. Bossier tight gas production is broken out into the shallow “Freestone” play and the “Deep Bossier” play. Early growth in the Bossier is attributed to the Freestone trend, while recent growth is from the deep trend. Deep trend growth has been very rapid over the past two years and is expected to ramp up greatly in coming years.

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[68] PTTC, 2008, April 2008 edition of PTTC Network News.
[69] IHS, 2007, Industry Highlights – May, 2007.
[70] Oil and Gas Journal, 2008, “Woodford: A Horizontal Anadarko Basin Target,” May 28, 2008.

Figure 29 North and East Texas District Natural Gas Production Trends

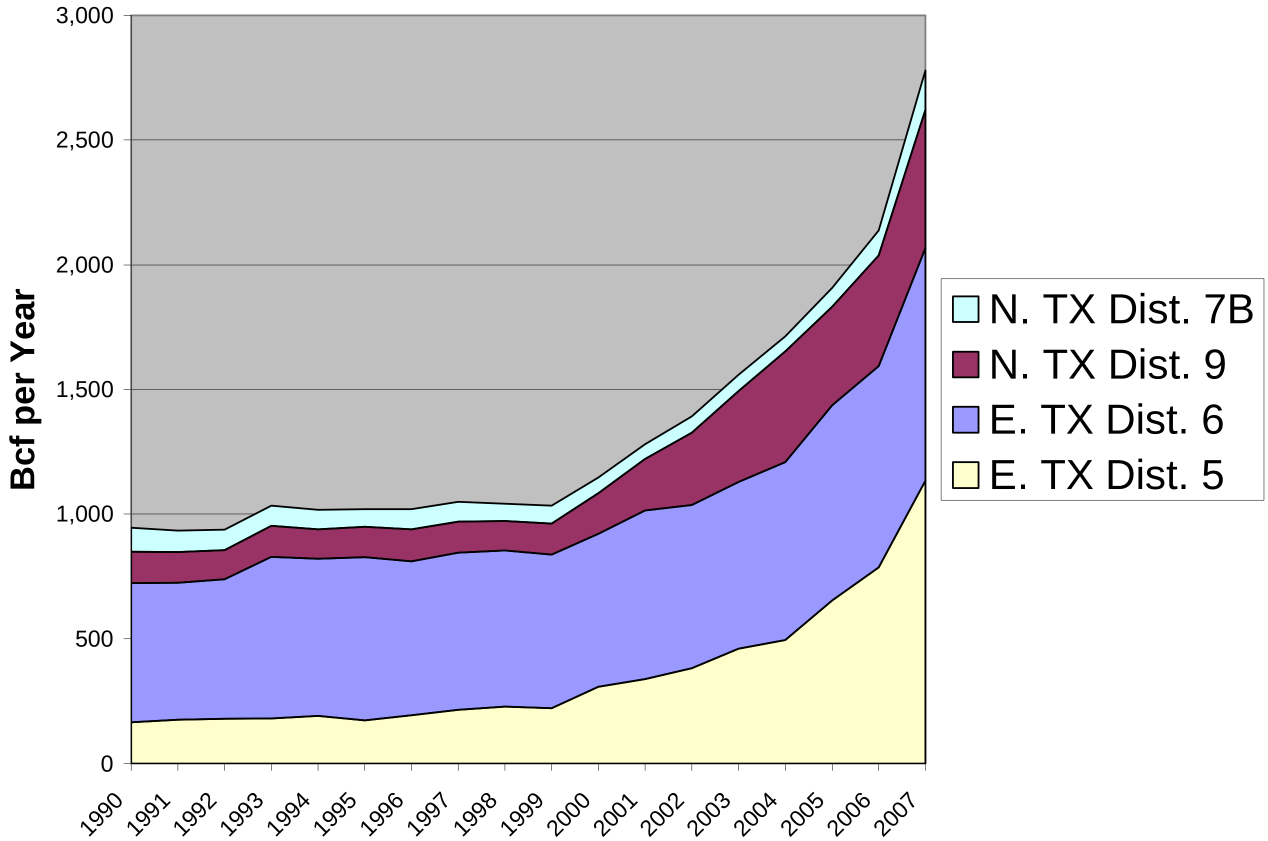
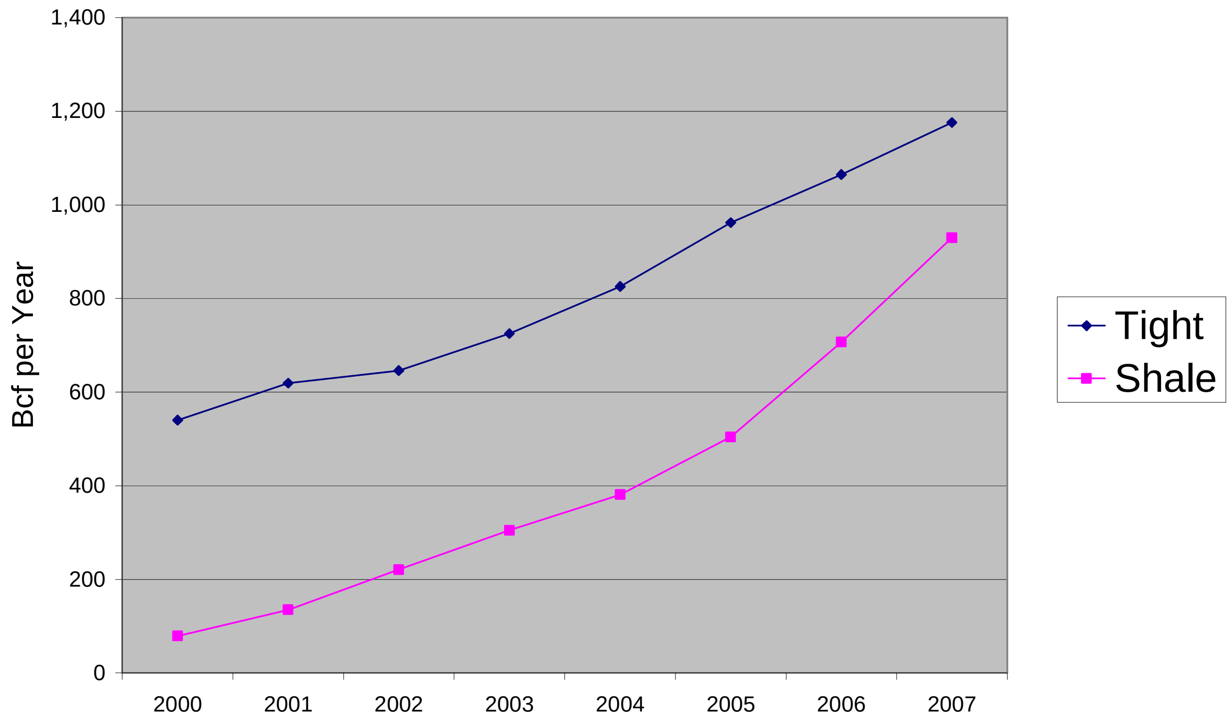


Table 21 North and East Texas Unconventional Natural Gas Production by Play

BCF per Year Raw Gas

Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	Change Since 2000
Fort Worth Basin	Shale	79	135	221	305	381	504	707	930	1077%
East Texas	Shallow Bossier Tight	107	158	194	242	280	286	282	290	171%
East Texas	Deep Bossier Tight	20	40	38	36	45	101	146	186	830%
East Texas	Cotton Valley	413	421	414	447	501	575	637	700	69%
Tight Total - Studied Plays		540	619	646	725	826	962	1,065	1,176	118%
Coalbed Total		0	0	0	0	0	0	0	0	na
Shale Total - Studied Plays		79	135	221	305	381	504	707	930	1077%
Total Unconventional		619	754	867	1,030	1,207	1,466	1,772	2,106	240%

Figure 30 North and East Texas Unconventional Natural Gas Production Summary



Barnett Shale – North Texas

Gas production from the Barnett Shale in the Fort Worth Basin continues to increase and the extent of the play is expanding. The Texas Railroad Commission reports that through April, 2008 there were about 7,500 Barnett Shale gas wells operating. The number of new drilling permits continues to increase, from about 1,100 in 2004 to over 3,500 in 2007. The top five operators on the basis of annual production were Devon, XTO, Chesapeake, EOG, and Encana.

Estimates of recoverable resources from the Barnett have increased consistently over the past decade or more. A 1996 USGS estimate was 3 Tcf; their current estimate is 26 Tcf. As discussed above, ICF developed a volumetric assessment with an unrisked gas-in-place volume of 1,150 Tcf and a potential recovery of 107 Tcf based upon ultimate 40 acre spacing. (Unrisked gas-in-place is based on volumetric calculations of thickness, area, and other factors without discounting for perceived geologic risk).

The ICF database indicates a 2007 production rate of 930 Bcf or approximately 2.62 Bcfd. That excludes associated natural gas (gas from oil wells) which is also increasing but represents a small fraction of total natural gas production (currently less than 30 MMcfd). ICF's production data are slightly higher than what the Railroad Commission (RRC) is reporting because they include an ICF estimate of reporting "lag". (There is often a long period of time before production reports are received and processed by state agencies). **Table 22** shows the completed production series from the RRC. Note the increase in oil production and casinghead (gas associated with oil) natural gas production. The Barnett has very significant oil production potential, and operators are beginning to use horizontal drilling techniques on the oil leg.

Current areas of high activity include Johnson and Tarrant Counties. Most of the new wells are horizontals using state of the art rigs. [71] In many cases, rigs are drilling multiple horizontal wells from a single pad.

Table 22 Newark East (Barnett Shale) Annual Natural Gas and Liquids Production

Texas RRC Website with ICF Estimate for 2007

Date	Oil (BBL)	Casinghead Gas (MMCF)	Gas Well Gas (MMCF)	Condensate (BBL)	Total Gas (MMCF)	Ratio of Condensate to Total Gas (BBL/MMCF)
2000	0	0	79,068	129,001	79,068	1.632
2001	4,524	95	134,562	402,197	134,657	2.987
2002	15,484	206	220,571	936,413	220,778	4.241
2003	37,705	454	304,067	1,172,485	304,521	3.850
2004	88,392	1,134	379,762	1,318,257	380,896	3.461
2005	155,175	2,459	501,699	1,450,062	504,158	2.876
2006	320,965	3,723	704,295	1,639,113	708,018	2.315
2007	624,059	7,541	955,063	1,702,482	962,604	1.769

Note: Source: Texas RRC production query site; 2007 data includes ICF estimate.

Bossier Tight Sand – East Texas

As stated above, the Bossier tight sand play consists of a shallow Bossier trend called the Freestone trend and the Deep Bossier play. The shallow Bossier is generally found at depths of 12,000 to 14,000 feet while the Deep Bossier is below 15,000 feet. [72] The ICF database indicates that about 2,500 wells have been completed in the shallow play and approximately 500 wells in the deep play.

The shallow trend produces in Freestone, Leon, Limestone, and Robertson counties and has been very active over the past decade. XTO is very active in the region, indicating an inventory of approximately 2,000 undrilled locations. [73] They reported year 2007 proved reserves of over 3 Tcf while running 28 rigs in the play. They have completed over 1,100 wells and report production of over 650 MMcf per day. With an estimated 2 Bcf per well from the undrilled 2,000 wells, the potential is about 4 Tcf just on their acreage. Most historic drilling has been with vertical wells. They have the potential to drill verticals on 20 acres and are also drilling horizontal wells. Devon is also active and is drilling some horizontal wells.

[71] PTTC, 2008, "PTTC Network News," Petroleum Technology Transfer Council, April, 2008.
[72] Oil and Gas Investor, 2006, "Tight Gas," March, 2006.
[73] XTO, 2008, March, 2008 investor slides.

Production from the deep trend is expanding rapidly. Operators include Gastar, Encana, Leor Energy, and ConocoPhillips. It has been reported that a typical range of EUR per well is about 5 to 7 Bcf, but some operators have reported reserves of over 20 Bcf per well. [74] The play is highly overpressured, meaning that it has higher pressure at a given depth than would be expected with a normal pressure gradient, enhancing well production rates. Reported well costs $8 to $12 million, but well productivity and recovery are very high.

Cotton Valley and Travis Peak – East Texas

The Jurassic Cotton Valley and Travis Peak formations have been active for decades but have seen a big increase in drilling activity over the past five years. ICF's database indicates that 2007 natural gas production from the Cotton Valley was 700 Bcf, up from 400 in 2000. Areas of significant activity include Carthage and Overton fields. [75] Devon is very active in the Cotton Valley in this area and a recent presentation indicated that they plan to drill 120 vertical wells and 23 horizontal wells in 2008.[76]

Near the Bossier development is the Cotton Valley limestone tight play. Also nearby is the James Lime play, which is very active south of the Cotton Valley developments. Cabot Oil and Gas is drilling James Lime horizontal wells and wells are testing at over ten MMcfd. Wells are 13,000 feet deep with a 5,400 foot lateral. [77]

Texas Gulf Coast

The Texas Gulf Coast has experienced a significant amount of tight gas activity. A major focus of the activity is in Texas District 4, which lies at the southern tip of the state. Several plays are active including the Wilcox tight sand. **Figure 31** shows the historic production for District 4 and **Table 23** and **Figure 32** show Wilcox production.

[74] Oil and Gas Journal, 2007, "Unconventional Gas – New Plays, Prospects, Resources Continue to Emerge," Advanced Resources International, OGJ September 24, 2007.
[75] Oil and Gas Investor, 2006. ibid.
[76] Devon, 2008, February, 2008 investor slides.
[77] Oil Voice, 2007, "Cabot Oil and Gas Announces Horizontal Drilling Success in East Texas, Nov. 15, 2007, http://www.oilvoice.com

Figure 31 Texas Gulf Coast District 4 Natural Gas Production

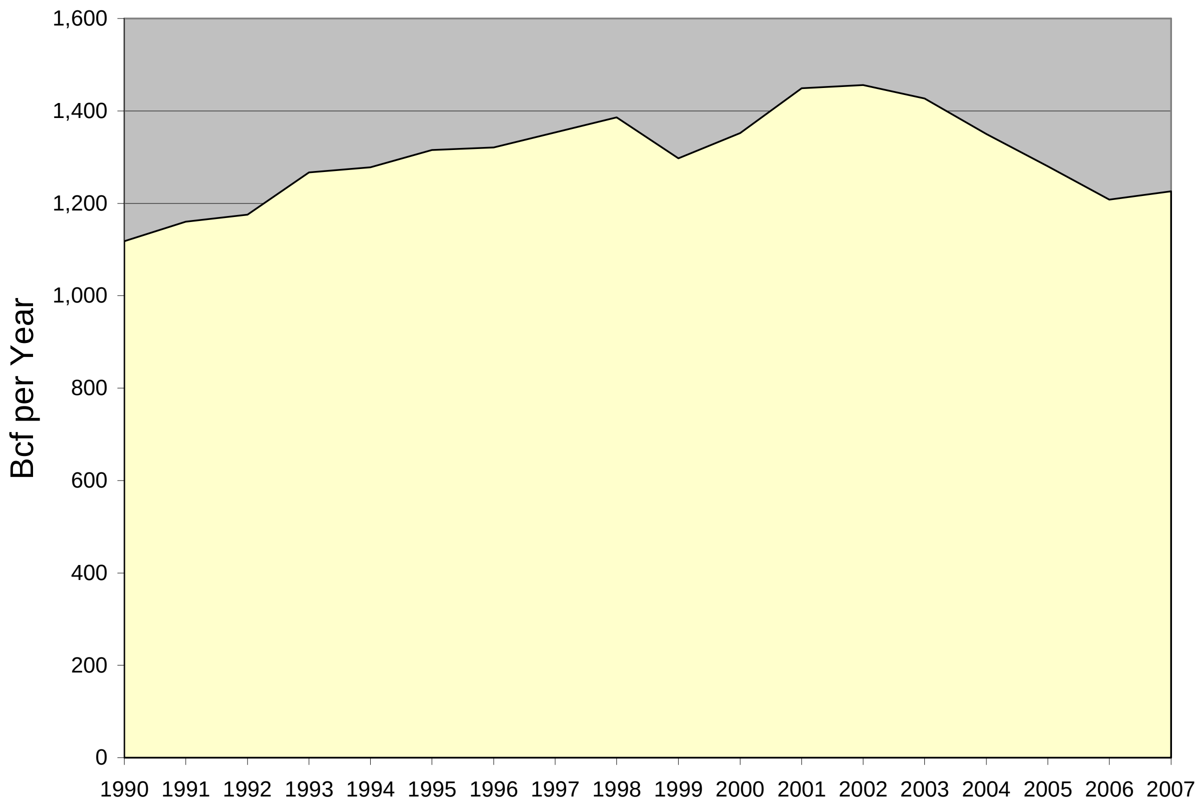
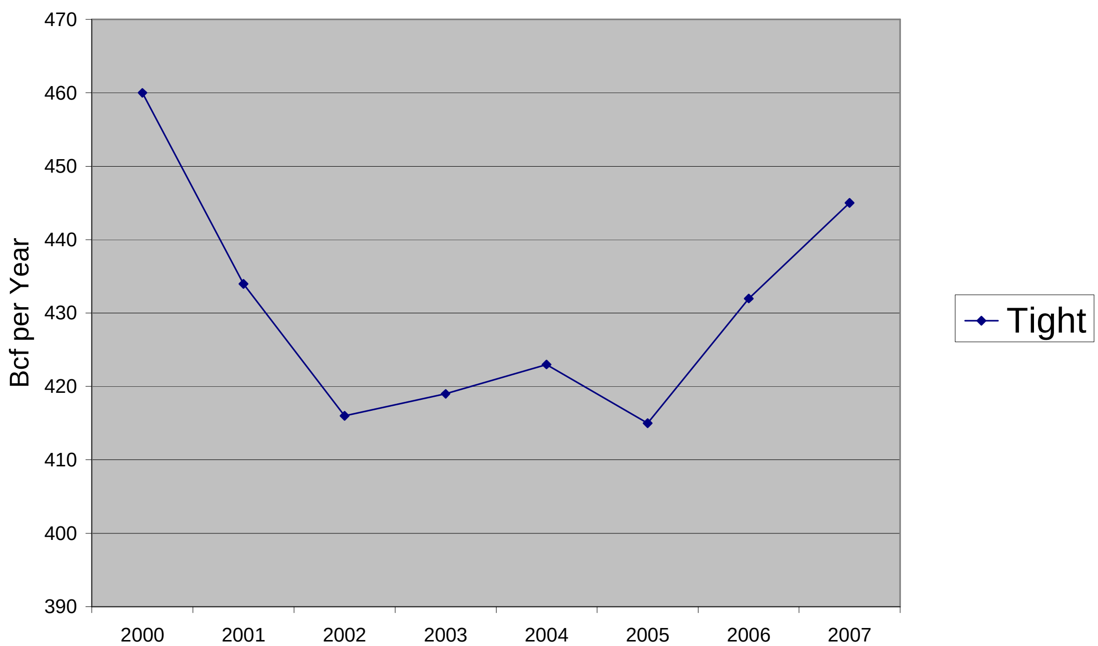


Table 23 Texas District 4 Unconventional Natural Gas Production by Play

BCF per Year Raw Gas

Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	Change Since 2000
Texas Gulf Coast	Wilcox Tight	460	434	416	419	423	415	432	445	-3%
Tight Total - Studied Plays		460	434	416	419	423	415	432	445	-3%
Coalbed Total		0	0	0	0	0	0	0	0	na
Shale Total - Studied Plays		0	0	0	0	0	0	0	0	na
Total Unconventional		460	434	416	419	423	415	432	445	-3%

Figure 32 Texas Gulf Coast Unconventional Natural Gas Production Summary



Southeast

The Southeast region consists of Alabama, Mississippi, and Louisiana. As shown in **Figure 33**, natural gas production in this region has been declining overall. **Table 24** and **Figure 34** show the contribution of the Warrior Basin coalbed methane.   As discussed below, significant activity is also taking place in tight gas and in the Haynesville Shale in Louisiana. Emerging shale plays in Alabama are also discussed.

Figure 33 Southeastern State Natural Gas Production Trends

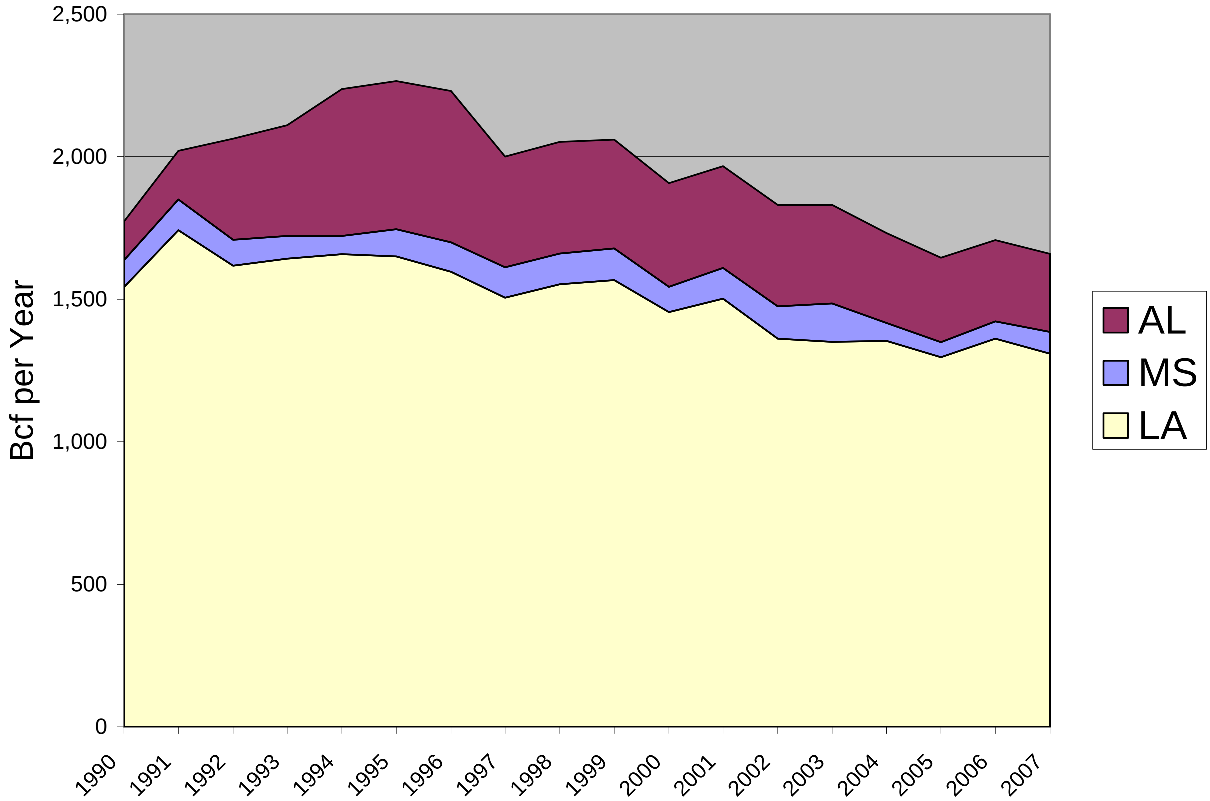
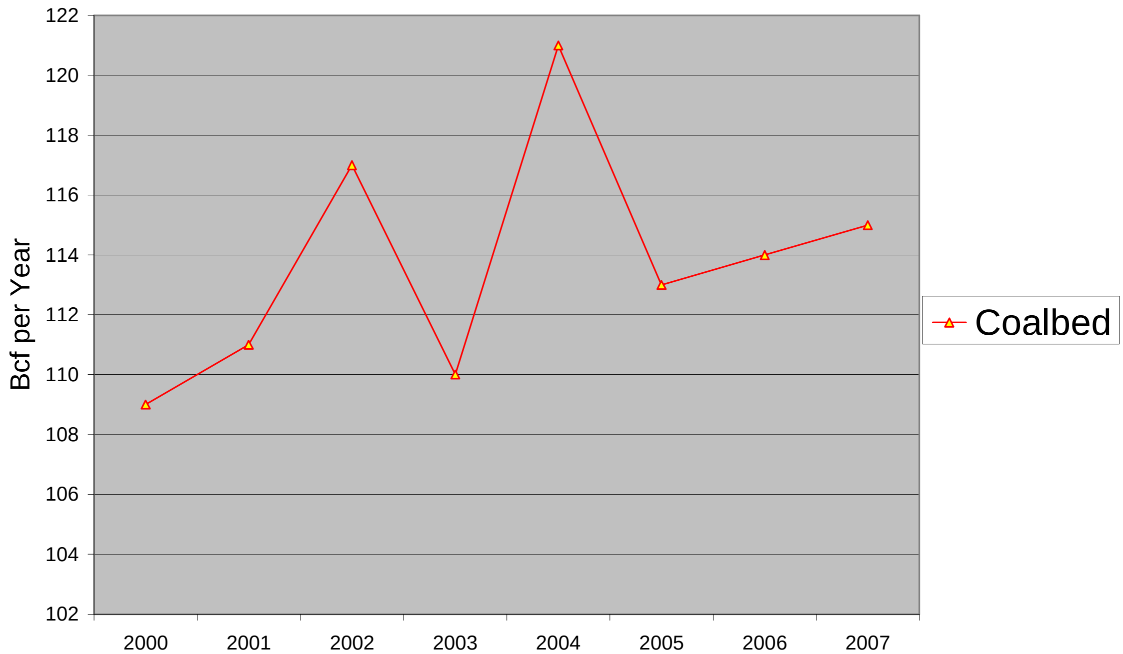


Table 24 Southeast Unconventional Natural Gas Production by Play

BCF per Year Raw Gas

Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	Change Since 2000
Warrior	Pottsville CBM	109	111	117	110	121	113	114	115	6%
Tight Total - Studied Plays		0	0	0	0	0	0	0	0	na
Coalbed Total		109	111	117	110	121	113	114	115	6%
Shale Total - Studied Plays		0	0	0	0	0	0	0	0	na
Total Unconventional		109	111	117	110	121	113	114	115	6%

Figure 34 Southeast Unconventional Natural Gas Production Summary



Haynesville Shale Play

In March of 2008, Chesapeake Energy announced the opening of a potentially large new shale gas play in northern Louisiana – the Jurassic age Haynesville Shale. The company indicated that their acreage has up to 20 Tcf of potential. Chesapeake is operating four rigs in the play and plans to increase operations to eight rigs by the end of 2008. They have not released the results of their drilling, but stated that they have completed four vertical wells and three horizontal wells. Well recoveries for Haynesville horizontals are expected to be in the range five Bcf.

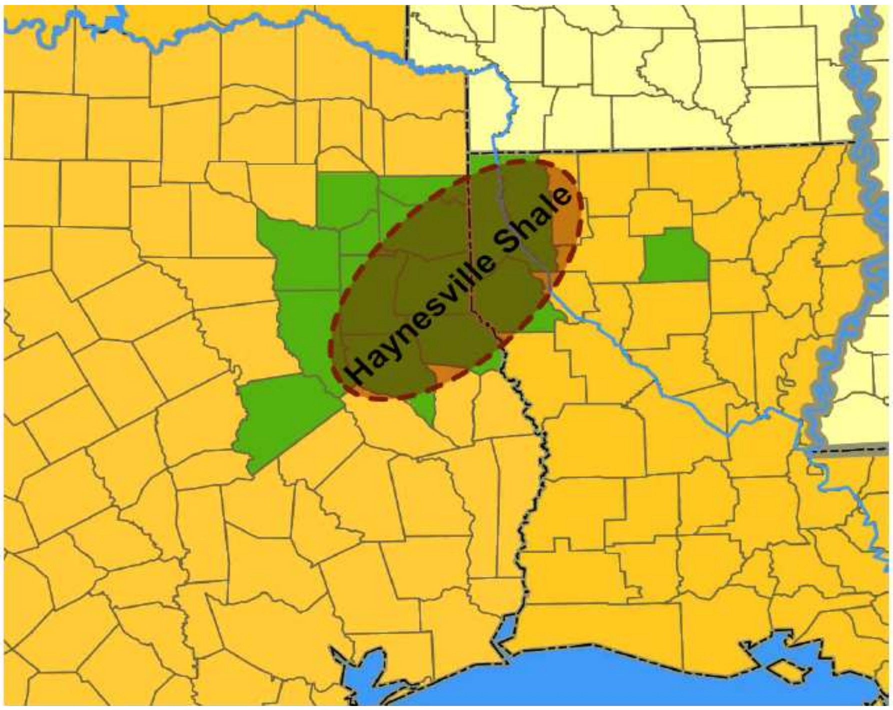
In addition to Chesapeake, operators include Petrohawk, Encana, Questar, El Paso, and a number of small independents.

The play is located primarily in the area of Caddo, DeSoto, Bienville, Bossier and Red River parishes in northwestern Louisiana, but it also extends into East Texas (**Figure 35**). This area description is based upon a map published by El Paso and EXCO resources. It is not yet apparent how far the play may extend beyond this area. Depths range from 10,500 to 13,000 feet and the shale is about 200 feet thick. The formation thins to the west into East Texas and becomes deeper from north to south. There are additional productive formations above the shale play including the Hosston and Cotton Valley formations This means that a given well may encounter several zones that could be completed.

In July, 2008, Petrohawk stated that they had three rigs running and planned to increase that to ten by the end of 2008. The company expects that 100 rigs will be running in the play by mid-2009, up from five at the beginning of 2008. [78]

Figure 35 Map of Haynesville Shale Play

Source: EXCO Resources



Petrohawk indicated the following parameters for economic analysis of the Haynesville: five Bcf per well recovery, completed well costs of $6.0 to $7.0 million, and 2,700 potential company sites on 60 acre spacing covering a net acreage of 150,000 acres. [79] "Risked potential" of 6.1 Tcf would equate to about half of the indicated five Bcf per well for 2,700 wells (Unrisked potential is 13.5 Tcf. Risked potential incorporates the operators view of geologic risk to the play extending across a specific area). Well depths are 10,500 to 13,000 feet, making it deeper than the Fort Worth Basin Barnett Shale.

An important aspect of the Haynesville play is that it is Jurassic in age, making the shale much younger than that of the Barnett and the other Devonian and Mississippian plays. Should the Haynesville be successful as the first non-Devonian/Mississippian major play, this may have implications for other potential non-Devonian shale plays in North America. [80]

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[78] Oil and Gas Investor, July, 2008, pg. 26.

[79] Petrohawk, May, 2008 investor slides.

[80] The Devonian period occurred approximately 360-420 million years ago, and the Jurassic Period occurred approximately 145-200 million years ago.

Bossier Shale in East Texas and Northwestern Louisiana

An emerging shale play that has received little press is the Bossier Shale of East Texas and North Louisiana. This play is being targeted by Petrohawk and is said to add additional potential to that of the underlying Haynesville. [81] It has a map distribution that extends to the south of the Haynesville and to the west into East Texas.

Cotton Valley and Hosston Tight Gas – Northwestern Louisiana

Questar reports that they have over 1,600 drilling locations in the Cotton Valley and Hosston formations in northwestern Louisiana. The EUR per well is 0.7 to 3.25 Bcf and drilling and completion costs are $1.7 to $2.5 million.

Conasauga Shale – Alabama

The Cambrian age Conasauga Shale has seen some exploratory activity in northeastern Alabama, but no significant production has occurred. A new shale gas field named Big Canoe Creek in Saint Clair county, Alabama has been established. [82] This area is in northern Alabama east of the Black Warrior Basin. Geologically it is in the Valley and Ridge province, a complex structural province trending northeast through the Appalachians. The field operator is Highmount Black Warrior Basin, a unit of Loews Corporation, which acquired it from Dominion Black Warrior Basin in 2007. Dominion drilled 14 wells in the field ranging from 3,400 to 9,000 feet deep. Initial tests ranged from 26 to 233 mcf per day. Eight wells produced about seven MMcf in August, 2007. The shale is very difficult to drill to the faulting and folding in the area.

Energen and Chesapeake have a joint venture and are involved in a five to ten well test program. [83] In early 2008, Energen filed permits for two 12,500 foot wells in Bibb County, about 95 miles southwest of Big Canoe Creek. They also permitted a well in Green County.

A 2006 shale test operated by Dominion reportedly blew out after encountering natural gas at 3,500 feet. [84] Field observers estimated the flow rate at between five and nine MMcfd. The area of interest is a valley with dimensions of 30 by five miles and consists of a highly folded sequence of shale that was deformed during thrust faulting.

Floyd Shale – Alabama

The Mississippian aged Floyd (and Neal) shale is age equivalent to the Barnett Shale and the Fayetteville Shale. The shale is termed Floyd Shale in Alabama and Neal Shale in Mississippi.

The organic rich zone of the Floyd shale ranges up to about 150 feet thick and has a depth range of 4,000 to 10,000 feet. [85] The formation has lateral geologic changes but is not complex structurally. In terms of organic carbon, a USGS report indicated an average total organic content

[81] Oil and Gas Investor, July, 2008, pg. 26
[82] Oil and Gas Journal, 2008, "Operators Chase Gas in Three Alabama Shale Formations," January 18, 2008.
[83] Energen, April 2008 investor slides
[84] Williams, Peggy, 2007, "Conasauga Saga," Oil and Gas Investor, September 1, 2007.
[85] Oil and Gas Investor, 2007, "The Floyd/Neil Shale," January, 2007.

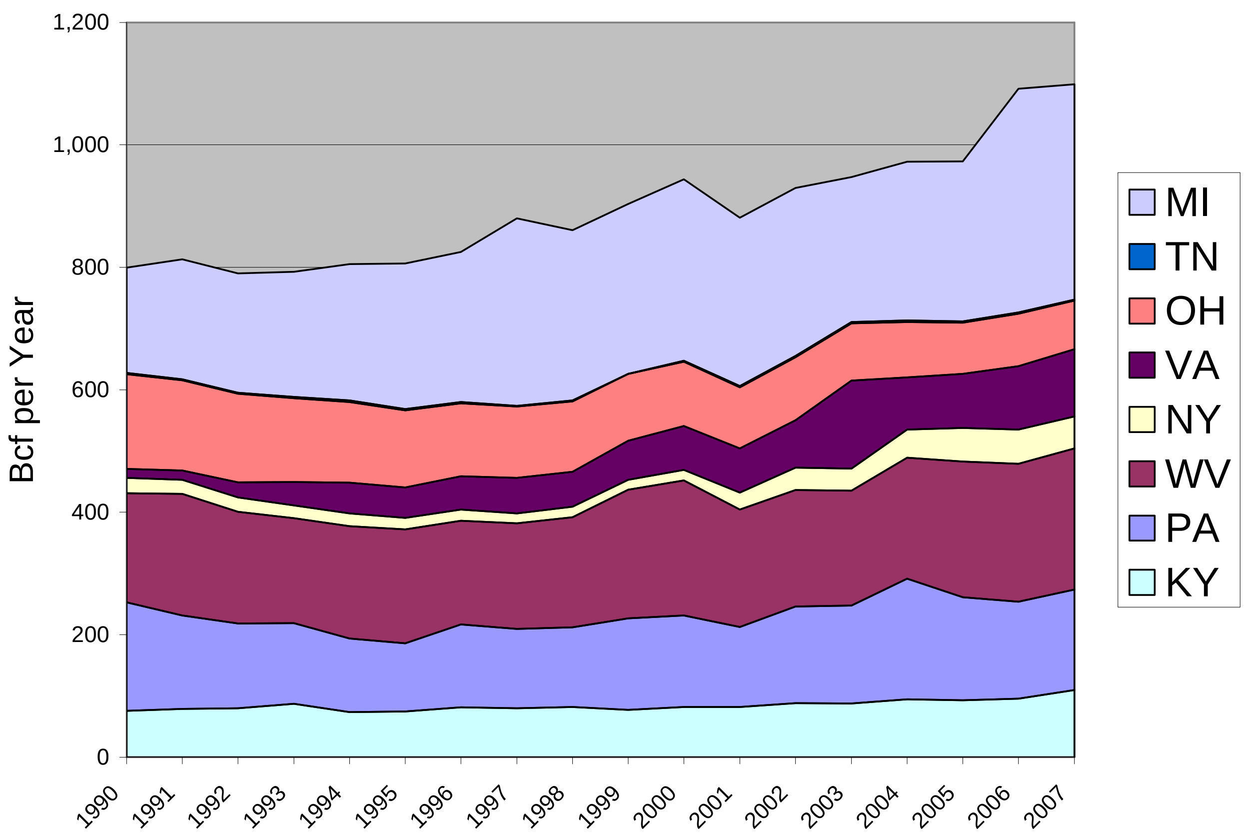
of 1.8 percent with a wide range of 0.5 to 10 percent. [86] (Organic content is a key factor in estimating shale gas potential. See Section 6 for a table showing the range of organic content for various shale plays).

Appalachian and Midwest Basins and Eastern Canada

The Appalachian Basin has produced natural gas from the Devonian Shale for over one hundred years. The basin also produces tight gas and coalbed methane. **Figure 36** shows production since 1990. Overall production was flat until the mid 90s, with production increases in recent years largely resulting from Michigan Basin Antrim Shale, Virginia coalbed methane, and West Virginia production.

Table 25 and **Figure 37** present the analysis of unconventional natural gas production.

Figure 36 Appalachian and Midwest State Natural Gas Production Trends



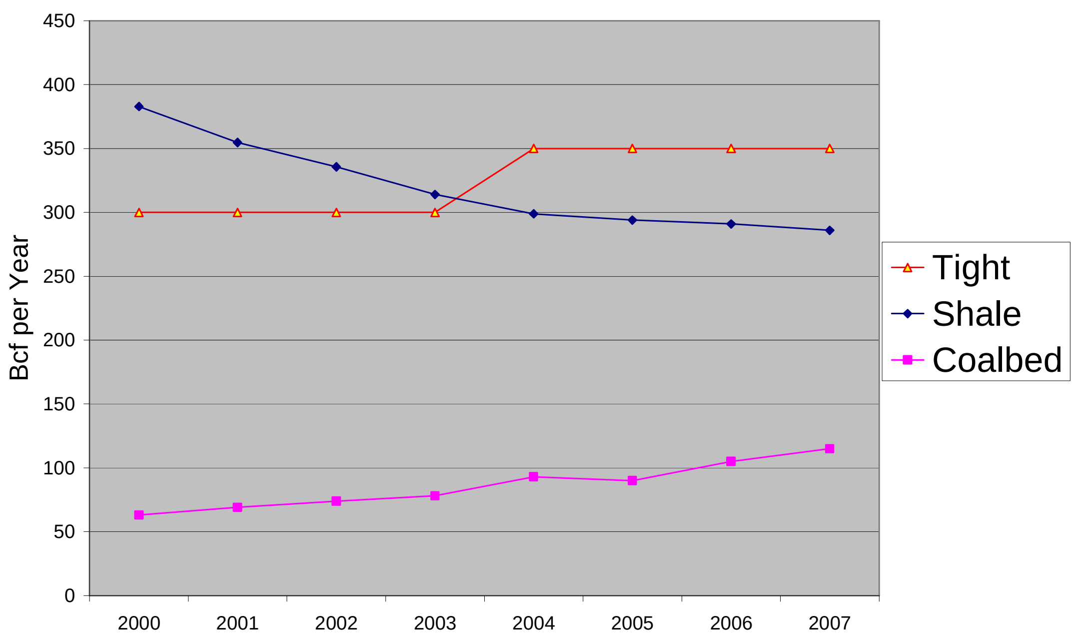
[86] Pawlewicz, Mark J., and Joseph R. Hatch, 2007, "Petroleum Assessment of the Chattanooga Shale/Floyd Shale Paleozoic Total Petroleum System," Chapter 3 of USGS Report DDS 69-I.

Table 25 Appalachian and Midwest Unconventional Natural Gas Production by Play

BCF per Year Raw Gas										Percent Change Since
Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	2000
Appalachian	Devonian Shale	200	180	170	160	150	150	150	150	-25%
Appalachian	Tight Gas	300	300	300	300	350	350	350	350	17%
Virginia	CBM	53	54	59	63	67	69	81	90	70%
PA and WV	CBM	10	15	15	15	26	21	24	25	150%
Michigan	Antrim Shale	183	175	166	154	149	144	141	136	-26%
Tight Total - Studied Plays		300	300	300	300	350	350	350	350	17%
Coalbed Total		63	69	74	78	93	90	105	115	83%
Shale Total - Studied Plays		383	355	336	314	299	294	291	286	-25%
Total Unconventional		746	724	710	692	742	734	746	751	1%

Notes: Appalachian Devonian Shale is produced in West Virginia, Kentucky, Ohio, Pennsylvania, Virginia, Tennessee and New York.
Appalachian tight gas is predominately the Clinton-Medina of eastern Ohio and western Pennsylvania, the Tuscarora which primarily occurs in Pennsylvania and West Virginia, and the Berea of western WV and southwestern VA.
The source for above Devonian Shale and Tight Gas plays was a 2007 EIA slide set on the Annual Energy Outlook with post-2004 ICF estimates.

Figure 37 Appalachian and Midwest Unconventional Natural Gas Production Summary



Marcellus Shale Play – Appalachian Basin

The Devonian age Marcellus Shale emerged in early 2008 as a potentially large new shale gas play. Operators have been testing both vertical and horizontal drilling across a very wide area representing the full known depositional extent of the Marcellus from West Virginia on the southwest to northeastern Pennsylvania and southern New York on the north (**Figure 38**).

Several large operators have announced that they have large acreage positions, including Range Resources, Chesapeake, Southwestern Energy, and Atlas Energy. Anadarko and EOG and Cabot are also active.

Although a number of operators have announced drilling plans, the play is in an early stage and it is difficult to forecast drilling activity and reserve additions, even over the near term.

Range Resources has drilled about 100 total wells including 20 horizontal tests. They have tested some rates on horizontals of up to 4.7 MMcf per day. In a July, 2008 press release, they stated that average reserves per well are expected to be three to four Bcf, horizontal well drilling costs are $3 to $4 million, and finding and development costs range from $0.90 to $1.60 per mcf equivalent. They stated that unrisked potential on company acreage is 15 to 22 Tcf, of which 10 to 15 Tcf is in southwest Pennsylvania and West Virginia, with the remainder in the northeast part of the play.

Chesapeake has stated that they plan to complete 165 vertical and horizontal wells in 2008 and 2009. They see potential in both the Marcellus and Huron.

Range Resources has announced potential resources of 15 to 22 Tcf, XTO may have two to four Tcf, and Atlas Energy may have four to six Tcf.

Geologically, the Marcellus extends across a very large geographic area, even in comparison to the Barnett. It is generally thinner than the Barnett, averaging about 50 – 200 feet. Organic content and maturity are favorable and depths are in a range of 5,000 to 8,500 feet.

In 2002, the USGS assessed the Marcellus as having 295 Tcf of natural gas-in-place, and technically recoverable resources of 1.93 Tcf of natural gas and 11.6 million barrels of natural gas liquids. [87] That assessment was based upon vertical wells and does not include the effects of modern fracturing technology. The extent to which the USGS included the deeper, more higher pressured parts of the play is not known. As discussed in Section 5, the ICF assessment of recoverable resources for this play is 63 Tcf. This is a preliminary assessment that is derived in part from the earlier USGS assessment of gas-in-place.

While the Marcellus is located close to eastern population centers, accessibility or ability to drill may hinder development in the play, at least relative to plays in Texas, Oklahoma, and Arkansas. For example, topography is expected to be a factor in some areas, resulting in either reduced access or higher costs. Industry analysts have mentioned the need for smaller, more portable rigs due to road and bridge infrastructure characteristics. If there is a need to construct non-standard rigs, this could impact the rate of activity.

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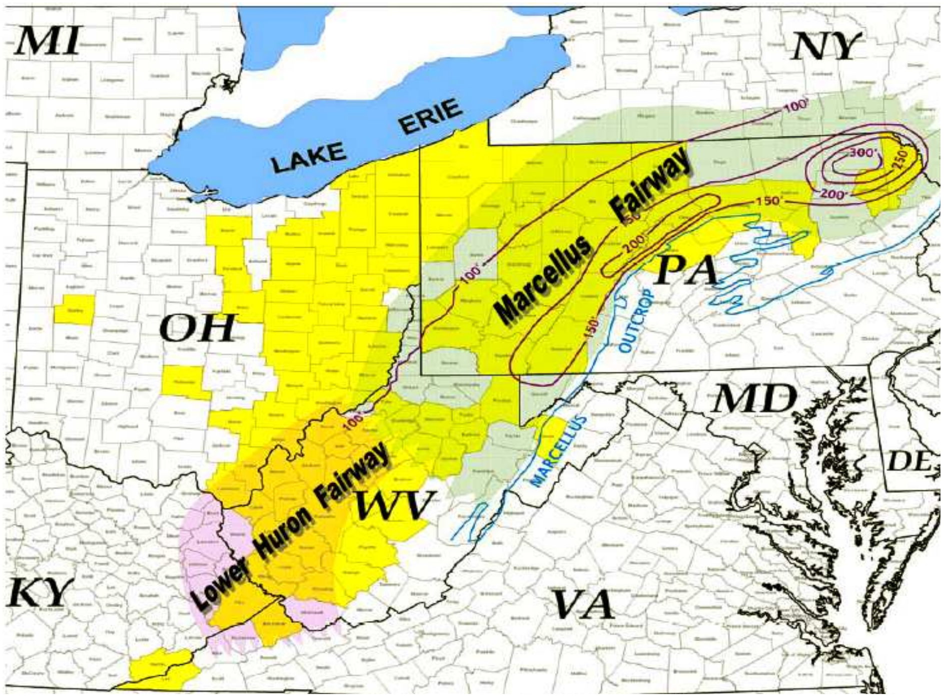
[87] USGS, 2006, "Assessment of Appalachian Basin Oil and Gas Resources: Devonian Shale – Middle and Upper Paleozoic Total Petroleum System," USGS Open File Report 2006-1237.

Figure 38 Map of Marcellus and Huron Shale

Source: EXCO Resources



Huron Shale Play – Appalachian Basin

The Devonian Huron Shale has been producing natural gas for more than a century from vertical wells in areas such as the Big Sandy Field in Kentucky. In 2006, Pittsburgh-based Equitable Resources began drilling horizontal wells in this low pressure shale play. [88] The company is air drilling these wells and using multiple fracturing stages and are having excellent success. To date, they have drilled more than 200 horizontals and plan to drill more than 300 in 2008. The wells cost $1.2 million per well and are expected to recover 0.75 to 1.50 Bcf, assuming at 3,500 foot lateral and nine fracture stages. Also, they are experimenting with the use of multi-lateral drilling, using many horizontal laterals to access the naturally fractured play instead of a single lateral with artificial fracturing. These multi-lateral wells are much less expensive due to the use of air drilling, but recover less gas. The production economics are said to be very good.

Utica Shale – Quebec and New York

In April of 2008, Forest Oil announced the discovery of natural gas in the Utica Shale in the St. Lawrence Lowlands between Montreal and Quebec. The discovery is still in the early evaluation project stage. Forest Oil estimates 4.1 Tcf of potential natural gas recovery on its acreage position of about 270,000 acres. This is based upon a 20 percent recovery factor (**Figure 39**). Other operators include Talisman, Gastem, Questerre, and Junex.

[88] Oil and Gas Investor, June, 2008.

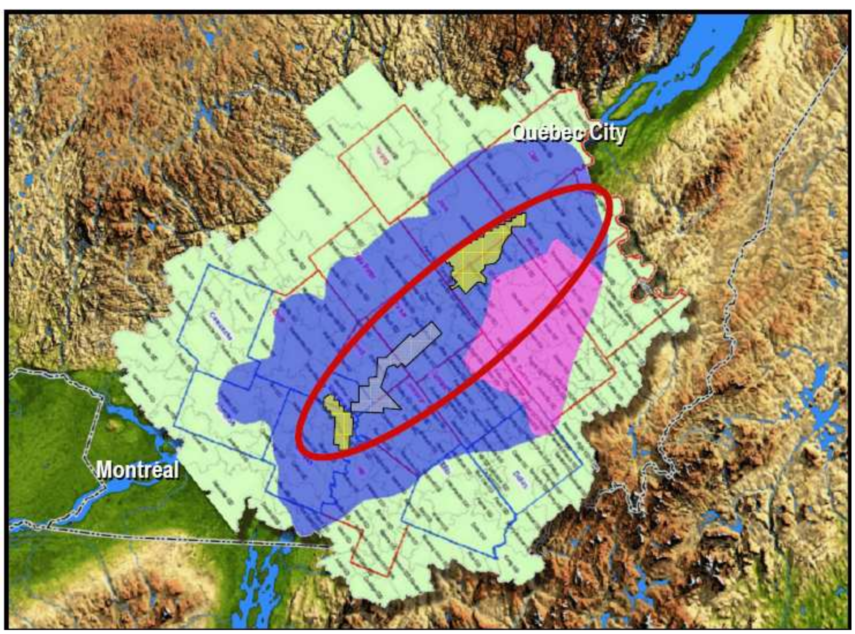
A Gas Daily article (April 7, 2008) indicated that the Utica Shale extends across much of southern New York and into Canada. In New York, the formation is about 12,000 feet deep, much deeper than the 2,000 to 6,000 feet of depth in Quebec. It lies below the Marcellus Shale, so that area may have dual formation potential in New York.

In Quebec, Forest Oil planned to drill three horizontal wells during 2008. First commercial production should occur in 2009, while a full-scale development project may occur in 2010, depending on drilling results. Two vertical wells were completed by Forest in 2007 with initial potentials of up to 1 MMcf per day and horizontal wells are testing at several times that rate, with 2,000 foot laterals and four fractures per lateral. The gas is 87-97 percent methane with less than one percent inerts (CO_2 or nitrogen) and a heating value of 1,027 to 1,136 Btu's. Currently, there is existing pipeline capacity to move the natural gas.

Geologically, the Utica is Ordovician in age, making it significantly older than the Devonian Marcellus and other Devonian and Mississippian organic shales. However, there is currently no reason to believe that geologic age is a significant factor affecting the unit's potential. The formation is about 500 feet thick. Total organic content is favorable, although it appears lower than the Barnett.

Figure 39 Location of Utica Shale Play

Source: Forest Oil, 2008



Shale Gas Plays in New Brunswick and Nova Scotia

Recently, Triangle Petroleum of Calgary announced participation in two emerging shale plays in Eastern Canada (**Figure 40**). The Horton Bluff Shale play is located in onshore Nova Scotia and the Frederick Brook Shale play is located in New Brunswick.

A study prepared by Ryder Scott of Calgary for Triangle Petroleum has a natural gas-in-place estimate for the Nova Scotia play of 69 Tcf. [89] [90] This study also indicated that total organic content is 13 percent and thermal maturation is favorable at 1.5 to 2.0 % vitrinite reflectance. Drilling depth ranges from 3,700 to 4,400 feet and thickness is 590 feet.

Triangle has announced plans to spend $30 to $33 million to test the Nova Scotia play with six wells. A 10,000 foot vertical test was planned for July of 2008. Both vertical and horizontal test wells are planned. Their lease area is 516,000 acres or 806 square miles. The Ryder Scott study focused on a 25 square mile area that is estimated to contain three Tcf of gas-in-place or 120 Bcf per square mile.

In the New Brunswick play, two other operators in addition to Triangle are active– Corridor Resources and Petroworth. Petroworth has a four well drilling program for 2008 with a rig capable of 7,500 feet. Corridor Resources is testing the potential for horizontal shale development in the Frederick Brook formation near their McCully field. They have not yet established production.

Figure 40 Shale Plays in New Brunswick and Nova Scotia

[89] Marciano, Vince, 2008, "The Four Horsemen of the Maritime Shale, www.statesidereport.com, June 2008.
[90] Ryder-Scott, 2008, "Resource Potential – Horton Bluff Formation, Windsor Basin, Nova Scotia," March, 2008. (from Triangle Petroleum website).

Permian Basin

The Permian Basin of West Texas is the location of significant tight gas activity and potential shale gas production. **Figure 41** shows the district level natural gas production since 1990. Conventional non-associated (gas well) and associated (oil well) production declined overall. This decline was somewhat offset by tight gas development, which has increased in recent years. Major tight formations in the basin include the Canyon and Morrow. **Table 26** and **Figure 42** summarize the unconventional natural production in the Permian Basin.

Figure 41 Permian Basin District Natural Gas Production Trends

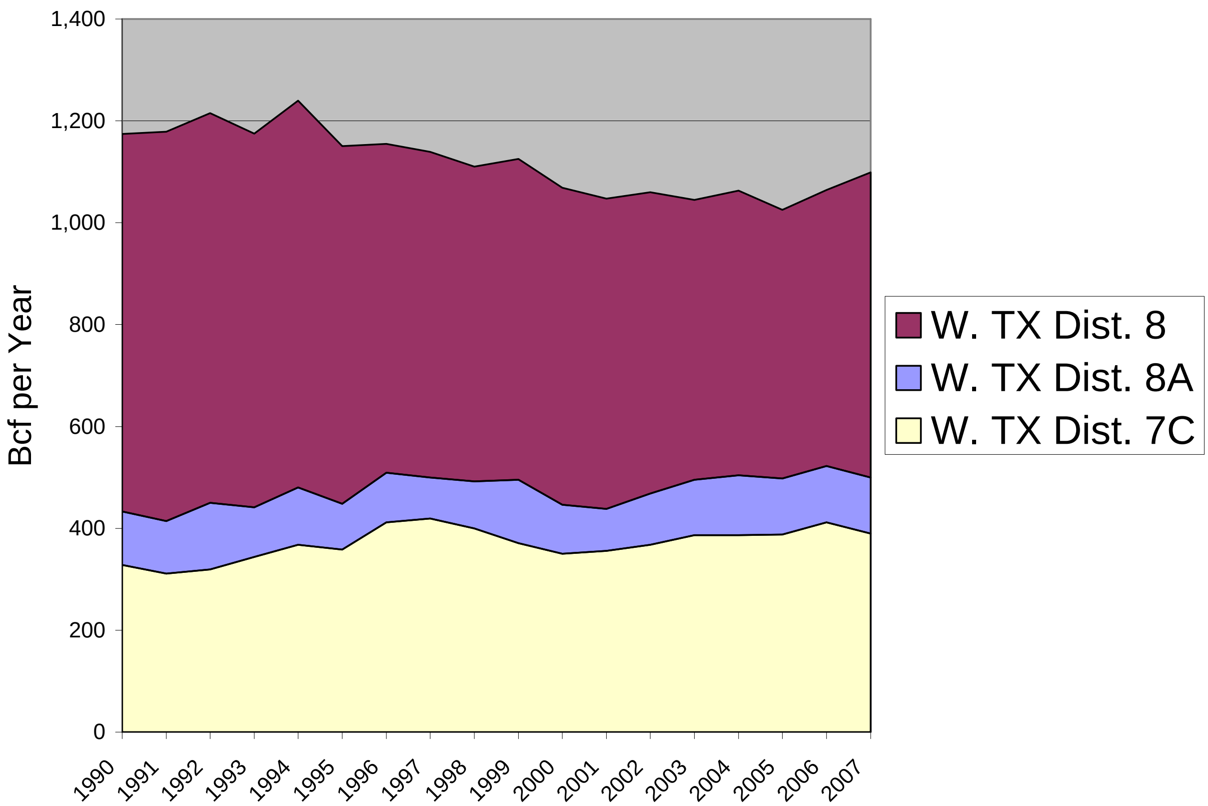
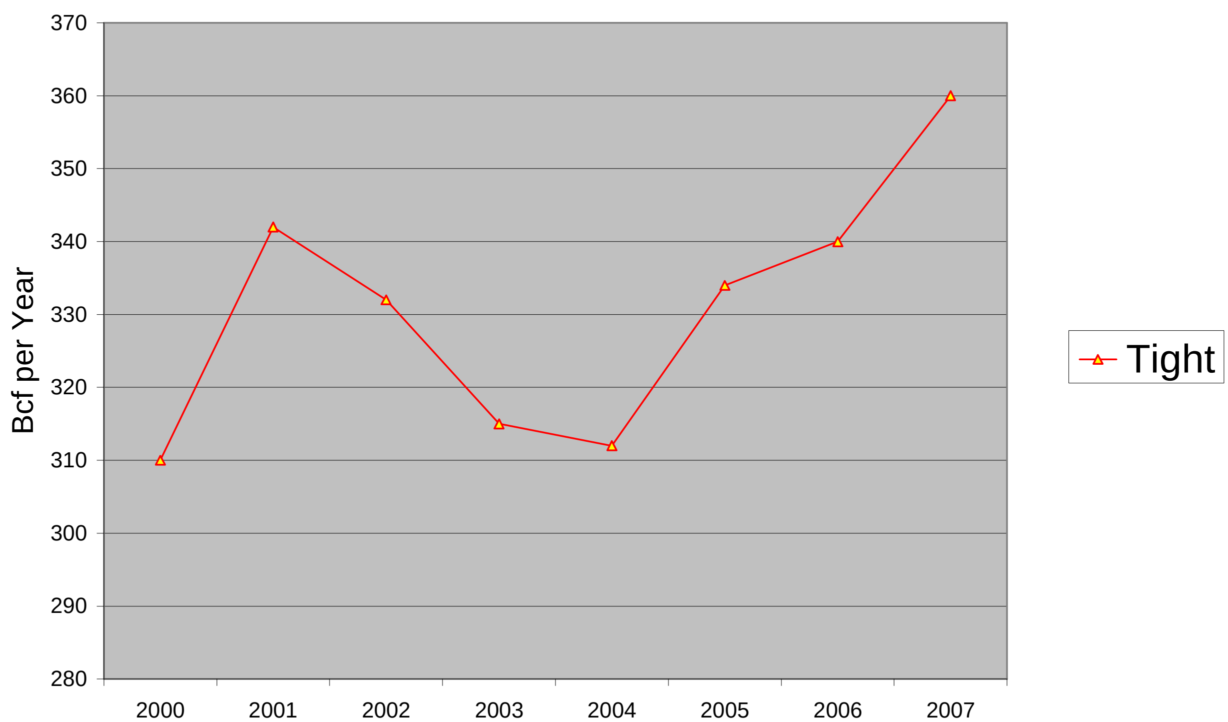


Table 26 Permian Basin Unconventional Natural Gas Production by Play

BCF per Year Raw Gas										Change Since
Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	2000
Permian	Canyon Tight	161	172	172	169	164	175	183	200	24%
Permian	Morrow Tight	149	170	160	146	148	159	157	160	7%
Tight Total - Studied Plays		310	342	332	315	312	334	340	360	16%
Coalbed Total		0	0	0	0	0	0	0	0	na
Shale Total - Studied Plays		0	0	0	0	0	0	0	0	na
Total Unconventional		310	342	332	315	312	334	340	360	16%

Figure 42 Permian Basin Unconventional Natural Gas Production Summary



Permian Basin Devonian Shale Play

Both the Barnett and Woodford organic shales are present in the Delaware Basin portion of the overall Permian Basin of West Texas. The Barnett shale ranges up to 800 feet thick, substantially thicker than in the Fort Worth Basin. The Woodford, which is only slightly deeper, is up to 400 feet thick. Total organic carbon is stated to be in the range of 4.5 to seven percent in Reeves County, Texas. In some areas of the play, the total shale thickness is up to three times as great as the thickness in the Fort Worth Basin.

Counties included in the play include Reeves, Brewster, Pecos, and Culberson Counties, Texas. The play is concentrated in the area of Reeves and Culberson Counties.

Little geological, well potential, or cost information has been published on the play. A typical drilling depth for the play is 12,500 feet or greater, with a range of 10,000 to 16,000 feet. This is much deeper than the Fort Worth Basin Barnett. The depth of the play has resulted in higher costs and more expensive, difficult completions. Well costs for vertical wells are said to be approximately $3 million and horizontal well are said to cost $4.5 million. [91]

Several operators have been active in the play including Chesapeake and Quicksilver. In 2007, Chesapeake had over 800,000 acres in the play with an unrisked potential of about 11 Tcf. Quicksilver indicates they have 375,000 acres with three to six Tcf of potential. Other operators include Conoco-Phillips and Encana. In 2007, Chesapeake stated that they had two vertical and two horizontal producing wells and eight wells in various stages of drilling and completion.

Quicksilver had planned five to six evaluation wells in 2007; it is unknown whether they have established commerciality. They do state, however, that they have an inventory of 1,000 – 2,000 well locations with potentially three Bcf per well. [92]

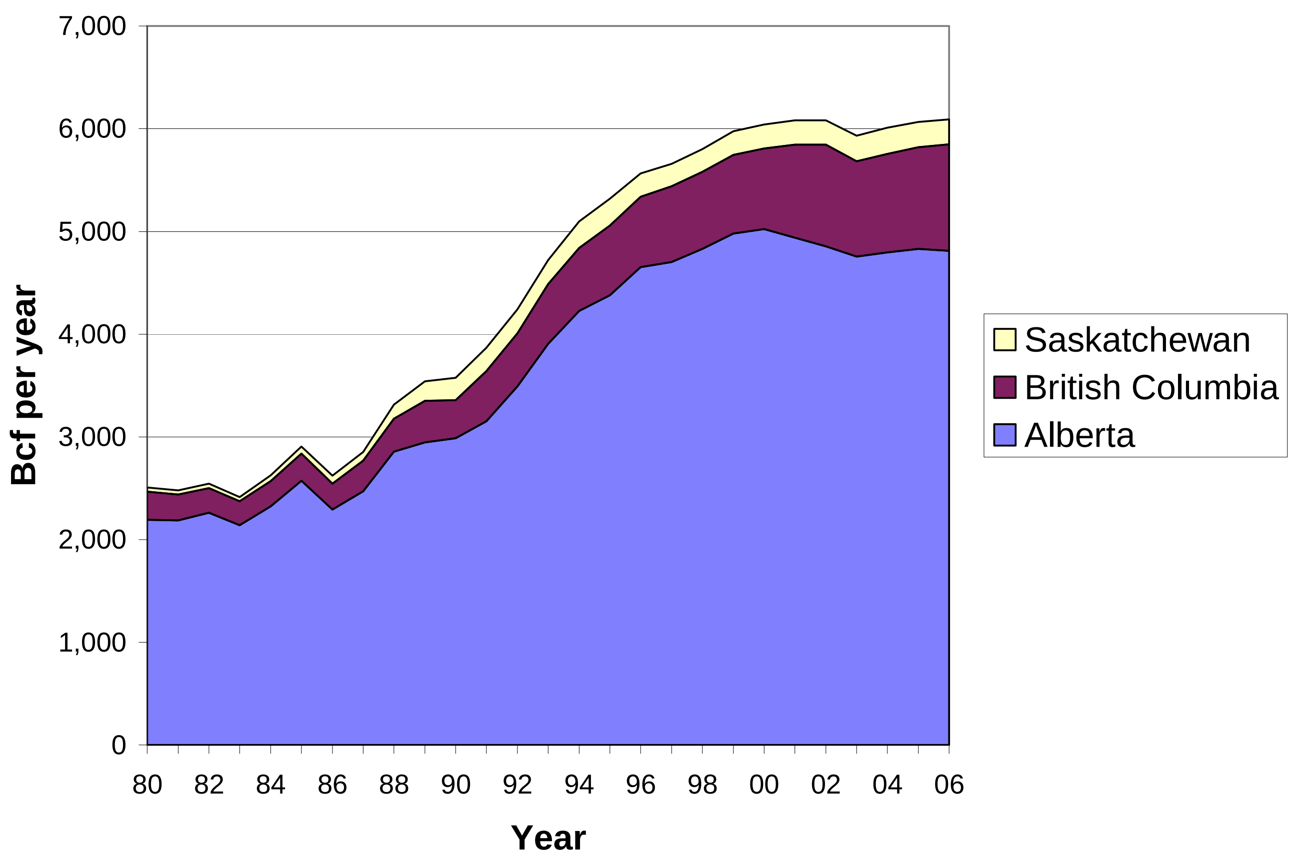
[91] Reisterberg, Robert, et al, 2007, "New and Emerging Unconventional Plays and Prospects," Oil and Gas Journal, August 3, 2007.
[92] Quicksilver Resources, April, 2008 investor slides.

Western Canada

The Western Canada Sedimentary Basin accounts for the vast majority of all Canadian natural gas production. The basin experienced a large increase in gas production in the 1990s. This increase was brought about by new development as well as production from previously discovered resources. In recent years, production has peaked, as shown in **Figure 43**. Coalbed methane activity has increased and an interest in deep, tight gas has emerged. The provincial government does not report tight gas, but information on coalbed methane is published and is summarized in **Table 27** and **Figure 44**. In 2007, coalbed methane production was approximately 650 MMcfd and was primarily from the dry Horseshoe Canyon formation. Industry plans to develop the deeper, and wet, Mannville coal beds. Mannville costs are higher but the wells are much more productive.

In terms of tight gas, the major activity is in Alberta's Deep Basin. The current rate of natural gas production from this area is 2.7 Bcfd. This is an increase from 1.7 Bcfd in 1996. A recent report by CSUG indicated a range of undeveloped potential of 16 to 30 Tcf. [93]

Figure 43. Western Canada Province Natural Gas Production

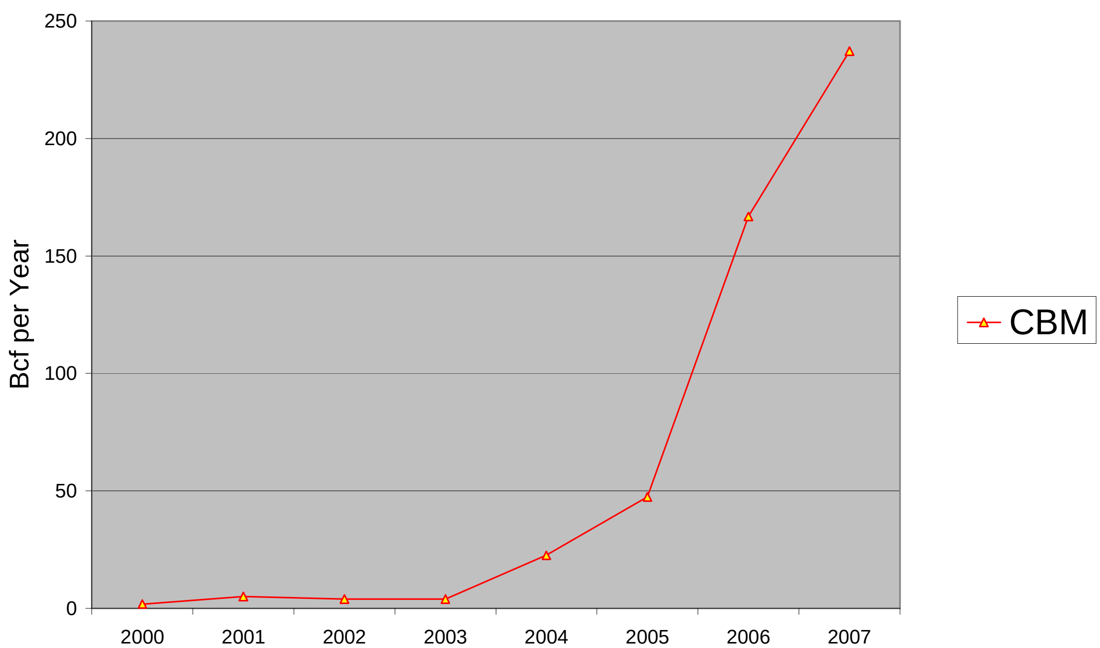


[93] Canadian Society for Unconventional Gas, 2007, "Deep Basin Tight Gas," presentation by Dave Flint and Bob Dixon, November, 2007.

Table 27 Western Canada Unconventional (CBM) Natural Gas Production

BCF per Year Raw Gas										Percent Change Since
Basin	Gas Type	2000	2001	2002	2003	2004	2005	2006	2007	2000
Alberta	CBM	2	5	4	4	23	47	167	237	12900%

Figure 44 Western Canada Unconventional Natural Gas Production (CBM Only)



British Columbia Western Canadian Sedimentary Basin Devonian Muskwa Shale

The Horn River Basin of northeastern British Columbia has seen a great deal of leasing and experimental shale gas drilling activity over the past two years. The play of interest is an organically rich Devonian age shale called the Muskwa Shale. According to the BC Ministry of Mines and Energy, since 2001, 16 drilled wells and five licensed undrilled locations had been granted experimental status through 2007. [94] Leasing activity in the play accelerated in 2006, with this

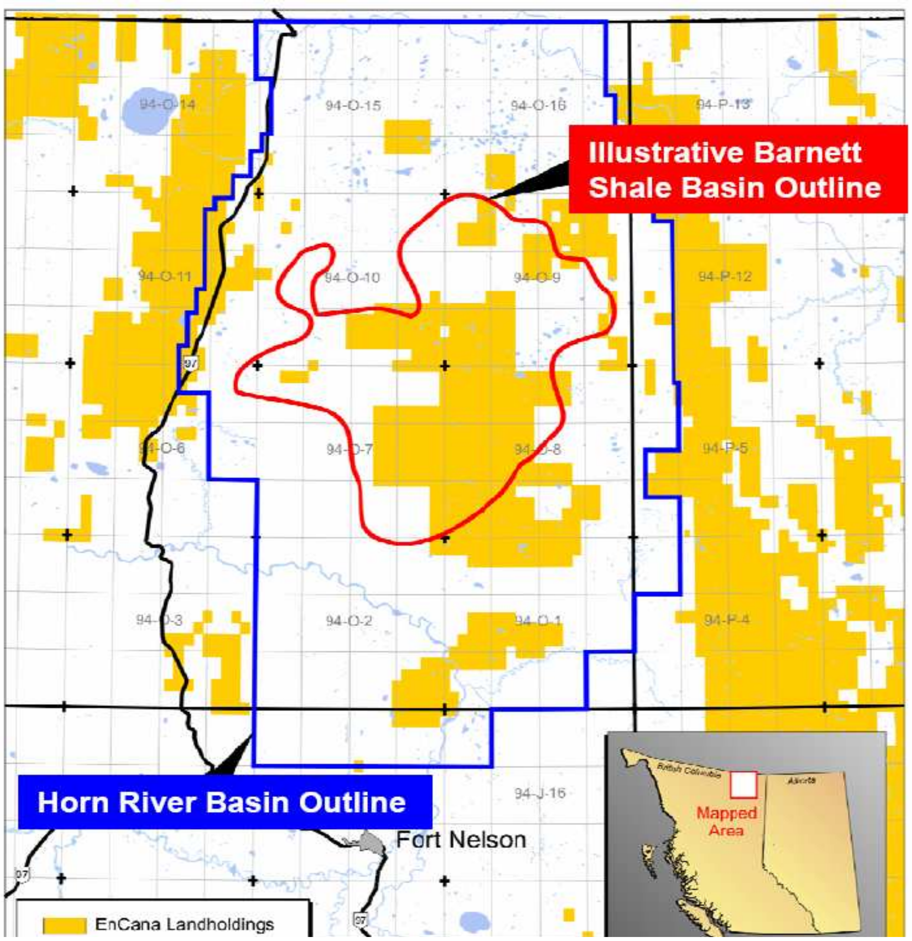
[94] British Columbia Ministry of Mines and Energy, Petroleum Geology Open File Report 2007-01.

trend continuing through 2008. Although gas has been tested from numerous wells, commercial production has not yet been established. **Figure 45** is a map of the area.

A recent report by consultant Wood Mackenzie indicated that the Horn River Basin may have recoverable reserves of 37 to 50 Tcf. [95] Further, recovery per well could be double that of the Barnett due to the shale thickness, organic content, and pressure. In addition, the play would require wellhead prices of $6.50 per MMBtu to be economically viable.

Figure 45 Map of Horn River Basin, BC Shale Play

Source: Encana, 2008



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[95] Gas Daily, May 8, 2008.

In April of 2008, Nexen announced it's new success in the Muskwa Shale. The firm has estimated that the potential for three to six Tcf of natural gas on 123,000 net acres. [96] Nexen has placed one horizontal and one vertical well into long-term production tests. Other operators in the play include Encana, Apache, EOG, Devon, ExxonMobil and Quicksilver.

Geologically, the Muskwa shale has many similarities to the Barnett. These include a thick section of organic shale with good silica content making it amenable to hydraulic fracturing. (Higher silica contents make shales more brittle and more amenable to fracturing). Well productivity and indicated reserves per well may be similar to or better than the Barnett.

Challenges for this area include remoteness, paucity of transportation and processing, winter drilling restrictions, and therefore, costs. Wells are expensive, in the range of $10 million to drill and complete. The Wood Mackenzie report discussed the challenges of developing gas in the remote basin, indicating that development would likely proceed much more slowly than in the Barnett, due to drilling and transportation infrastructure constraints.

To encourage development, the province of British Columbia has adopted an oil-sands like royalty framework for shale gas development. [97] This framework improves profitability by reducing the royalty rate. Once a project is approved, the royalty is two percent of gross reserves until capital costs are recovered. It then rises to a maximum of five percent of gross proceeds or 35 percent of net profits, whichever is greater.

Nexen has drilled several wells over the past two drilling seasons with good success. Horizontal completions are testing at four to eight MMcf per day with four to six 6 Bcf per well.

Apache believes that the potential on their acreage is in the range of nine to 16 Tcf. Assuming the potential is about 12 Tcf over the company's 323 square miles, recovery per square mile would be 37 Bcf. Apache's first three horizontals tested at rates of eight, six, and five MMcf per day.

EOG has estimated 318 Bcf per square mile of gas-in-place and has drilled three horizontal and three vertical wells. Recent horizontals tested in the range of three to four MMcf per day. Further, EOG estimates six Tcf on their acreage. First production is expected in the second quarter of 2008 with significant production starting in 2010.

Quicksilver plans to develop four wells in 2008 and states that recovery per well will be approximately five Bcf. [98]

ICF has determined that the area encompassed by current drilling, as shown on a map published by the BC Ministry of Energy and Mines, is about 750 square miles. [99] The total geological basin is approximately 5,000 square miles and the total play area could be as large as 2,000 square miles.

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[96] Gas Dail*y*, April 24, 2008.
[97] Energy Investment Strategies, 2008, "Huge Discoveries in Northeast Ignite 'Massive Land Grab' for Drilling Rights" David Ebner, March 3, 2008. http://www.energyinvestmentstrategies.com/2008/03/03/huge-bc-natural-gas-find-boosts-some-stocks/
[98] Fort Worth Star Telegram, May 21, 2008.
[99] British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2008. http://www.em.gov.bc.ca

British Columbia Western Canadian Sedimentary Basin Triassic Montney Shale

The Triassic age Montney formation has emerged as a new horizontal shale gas play in the Swan Lake/Cutbank Ridge area of northeast British Columbia. The play is in the early stages of development, with a number of pilot projects underway. The overall Montney-Doig interval has been developed for many years. However, those wells were completed in low permeability sands. Recent horizontal activity has targeted both tight sands and shales, and the geology of this interval differs from Devonian shales, which tend to be all or mostly organic shale.

A 2008 BC Ministry of Energy assessment study assessed the Montney Shale in British Columbia (it excludes the portion of the play in Alberta) at 80 Tcf of gas-in-place, indicating a possible recovery of about 20 Tcf. [100] [101] Of the 80 Tcf, 30 Tcf is the Upper Montney and 50 Tcf is the Lower Montney. This assessment includes both sand and shale units. According to the BC Ministry of Energy, about 40 horizontal natural gas wells and 100 vertical well are currently producing in the Upper Montney, although these are tight sand rather than shale wells. [102] Horizontal activity in the overall play has increased substantially over the past two years.

Encana is the largest leaseholder in the Montney and they are active in the Cutbank Ridge area (**Figure 46**). Encana is developing both tight sand and shale gas with horizontal drilling. Their overall production in the area is 208 MMcfd, of which 125 MMcfd is the Montney. [103] Industry trade press reports that Encana is planning 50 horizontal Montney wells in 2008 and a total of 90 horizontals are expected to be drilled in 2008. Encana is also expanding the pipeline and compression infrastructure in the area. The company is doubling capacity at its Steeprock plant to 140 MMcfd, allowing a significant increase in Montney production by year's end. [104] They anticipate an increase to approximately 1 Bcfd, but have not provided a timeframe for the increase. They have also indicated that horizontal well recoveries are expected to be five Bcf.

Other operators include Duvernay Oil, ARC Energy Trust, Storm Exploration, and Birchcliff, Murphy, and Sabretooth.

Well costs for horizontal Montney wells are about $4.5 to $5.5 million. Lateral well sections are up to 7,000 feet. [105] Initial potentials range from 2.5 to 5 MMcf per day. Wells are expected to be spaced at four per square mile. Encana indicates that the cost per completed interval in the Montney is $1 million. It does not state the typical number of completed intervals.

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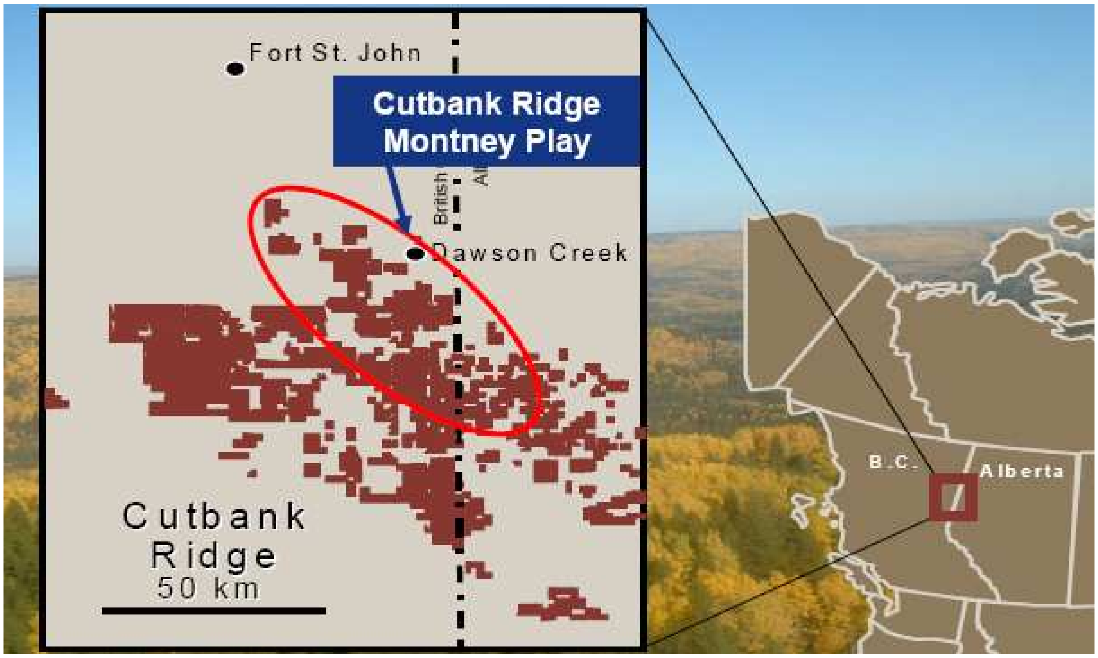
[100] Gas Daily, March 25, 2008.
[101] BC Ministry of Mines, "Regional Shale Gas Potential of the Triassic Doig and Montney Formations, Northeastern British Columbia," Open File Report 2006-02.
[102] BC Ministry of Energy, Mines, and Petroleum Resources, 2008. http://www.em.gov.bc.ca/subwebs/oilandgas/petroleum_geology/uncog/maps/Mar27_TriassicMap.pdf
[103] Gas Daily, June 3, 2008.
[104] Gas Daily, June 3, 2008.
[105] Nickles Daily Oil Bulletin, http://www.dailyoilbulletin.com

Figure 46 Location of Triassic Montney Shale, British Columbia

Source: Encana, May, 2008



7 WELL RECOVERY AND RESOURCE DEVELOPMENT COSTS

7.1 National Upstream Costs

The costs of upstream activity, including drilling, stimulation, and completion, have increased dramatically in recent years. There are many factors behind this, but the primary ones have been increased demand for quality drilling rigs, limited availability of quality personnel, and increased commodity costs.

There have been steep increases in the cost of materials and labor used in the construction of all types of energy infrastructure, including power plants, pipelines and oil and natural gas wells. **Figure 47** shows the recent history of cost per ton of carbon steel plate (used in line pipe, casing, pressure vessels, etc.) **Figure 48** shows the average day rate for onshore drilling rigs in the U.S.

The day rate for onshore rigs is a key factor in U.S. drilling costs. The average day rate essentially doubled between 2003 and 2007. [106] This had a major impact on overall resource development costs, especially when combined with cost increases for materials. The chart indicates that the day rate appears to have peaked in 2006 and early 2007. The slight decline in 2007, in part, reflects the addition of new rig capacity.

Although not included in the day rates, another factor driving costs in the unconventional plays is the reservoir stimulation component. The stimulation component has increased greatly as operators employ newly developed techniques that can cost several hundred thousand dollars or more per well. Vertical unconventional wells such as those at Jonah-Pinedale receive numerous fracture treatments, adding greatly to the well costs. Horizontal shale wells are expensive because of the horizontal drilling component and complex stimulation.

[106] Land Rig Newsletter. http://www.landrig.com

Figure 47 U.S. Carbon Steel Plate Prices

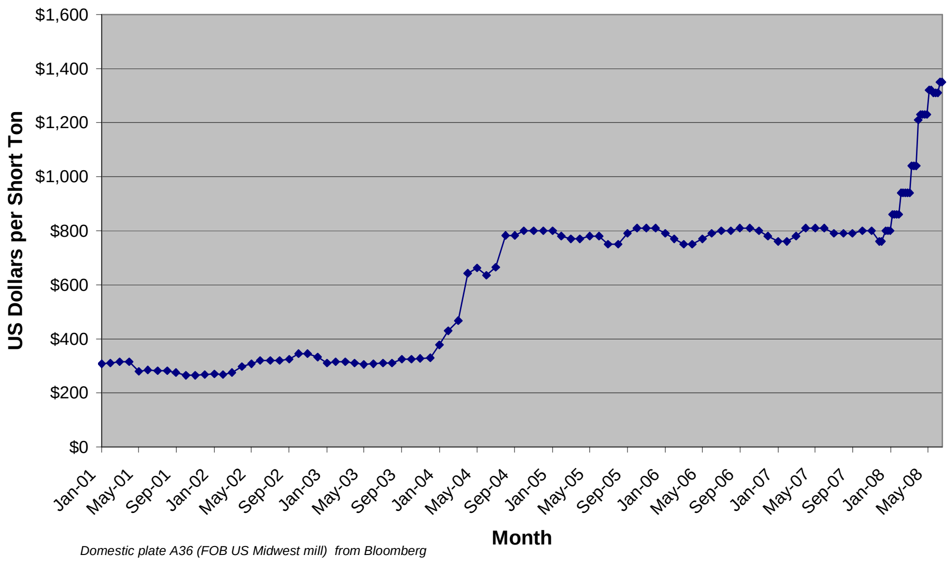
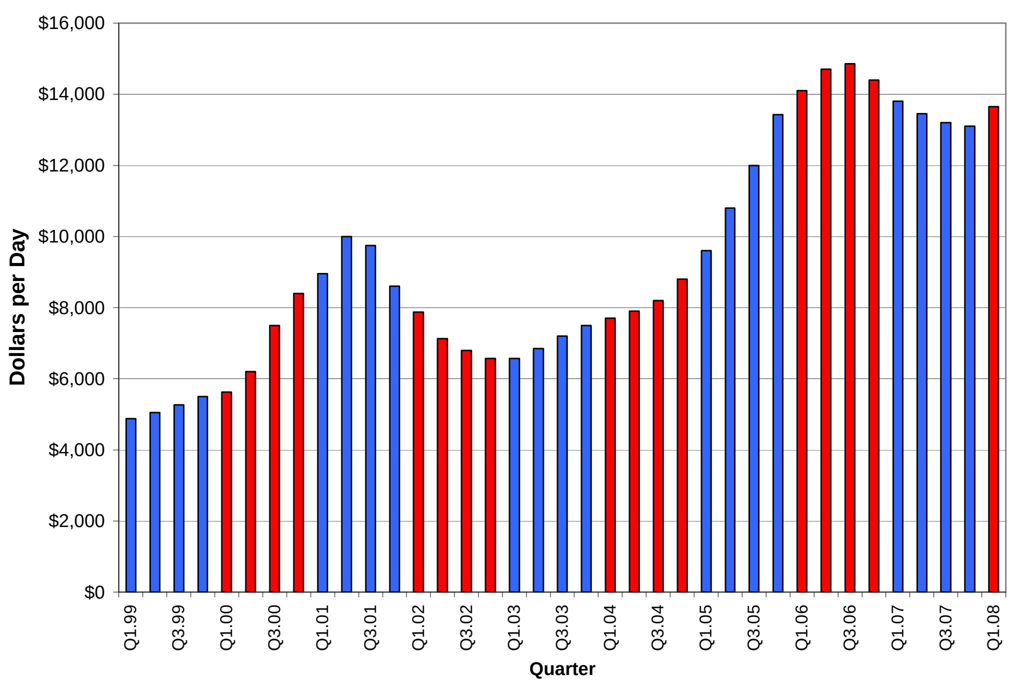


Figure 48 U.S. Drilling Rig Day Rates

Source: Land Rig Newsletter; various reports through first quarter, 2008.



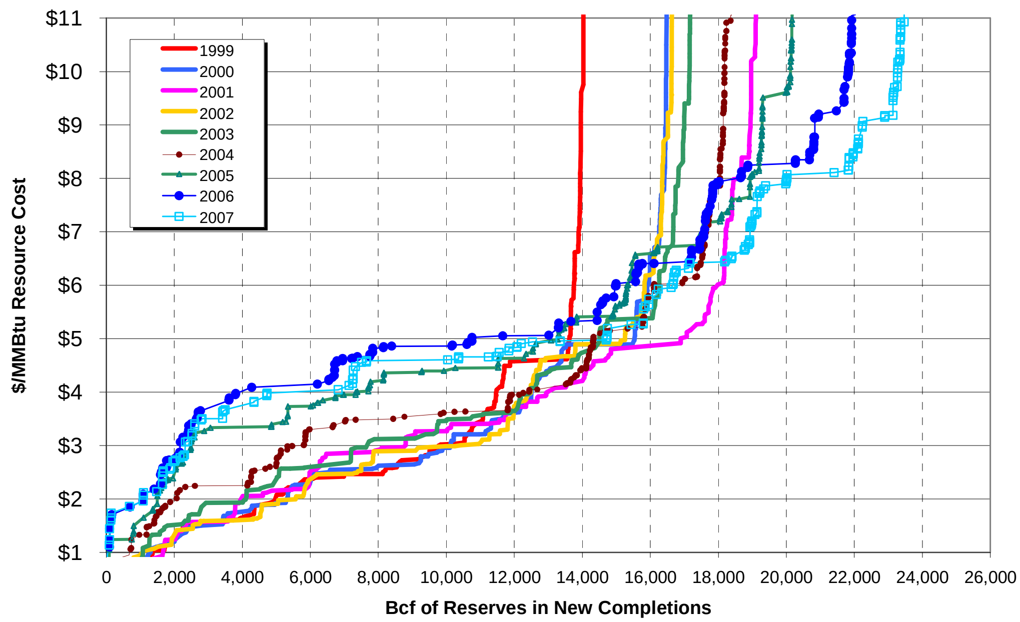
7.2 Resource Cost Approach and Results

ICF has developed the Play Level Cost Model (PLCM) to determine cost of natural gas reserve additions in the U.S. nationally, regionally, and by formation or play. It includes representations of approximately 400 plays in the U.S., including both conventional and unconventional natural gas. Play examples include the coalbed methane play in the Powder River Basin, the shallow Bossier Trend, and the Barnett Shale.

The PLCM computes the wellhead "resource cost" of each play or formation. The *wellhead resource cost* is the total required wellhead price needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes and income taxes. In this approach, the cost is applied to actual investments made and reserve additions in a historical year. A supply curve is built by summing all of the volumes added by play according to their resource costs. The wellhead resource cost excludes the costs required for gathering, compression, and transport to the mainline. For example, in the Rockies, such costs typically range from 12 to over 80 cents per thousand cubic feet. In addition, gas losses in the range of two toten percent can be expected due to gas use for compression and processing fuel. Compression costs are greatest in low pressure plays such as the coalbed methane plays or older plays with low wellhead pressures.

The annual distribution of wellhead resource costs across Lower-48 plays is shown in **Figure 49** for nine years of data. The figure shows cumulative non-associated (gas well) gas reserve additions from new natural gas completions sorted from the cheapest plays to the most expensive. Note that because actual costs are used, all values are in nominal dollars.

Figure 49 Annual (Conventional and Unconventional) Lower-48 Non-Associated Natural Gas Wellhead Cost Curves



To take the year 2007 of **Figure 49** as an example (the light blue line with open squares) the total non-associated reserves added was 24 Tcf. Of that amount, approximately 14 Tcf was added at resource costs below $5.00 per MMBtu, and six Tcf was added below $3.00. The curve from the 1999 wells shows that a large quantity of reserves was added below $3.00 per MMBtu (about 10 Tcf). However, the total reserves added in 1999 were only 14 Tcf. Overall, this shows that operators are adding a lot more reserves, but those reserves are being added at much higher costs. Note t hat since well-level production data are not reported for oil wells throughout the U.S. no similar curve can be created for the approximately 2 Tcf per year of reserve additions coming from associated-dissolved gas.

Figures 50 through 53 show the breakout of annual reserve addition costs by type of natural gas for the Lower-48. The light blue lines with open squares represent 2007 reserve additions. With tight gas (**Figure 50**, there was little resource proven in 2007 with costs below $4.00 per MMBtu. Half of the tight gas reserve additions have resource costs up to $5.00. About four Tcf out of the 14 Tcf total had costs above $8.00.

Coalbed methane costs are shown in **Figure 51**. Of the 1.9 Tcf of reserves added, a substantial fraction (about 1.3 Tcf) was at resource costs below $3.00 per MMBtu. The shale gas reserve additions displayed in **Figure 52** are primarily the Barnett Shale, since the Fayetteville and Woodford have not been developed as extensively. Most of the shale resource developed is $4.00 per MMBtu or higher resource costs. Conventional costs are presented in **Figure 53**. These curves show that the total conventional reserve additions in recent years have been lower, and little conventional natural gas is being added at costs below $4.00.

Figure 50 Annual Lower-48 Tight Gas Wellhead Cost Curves

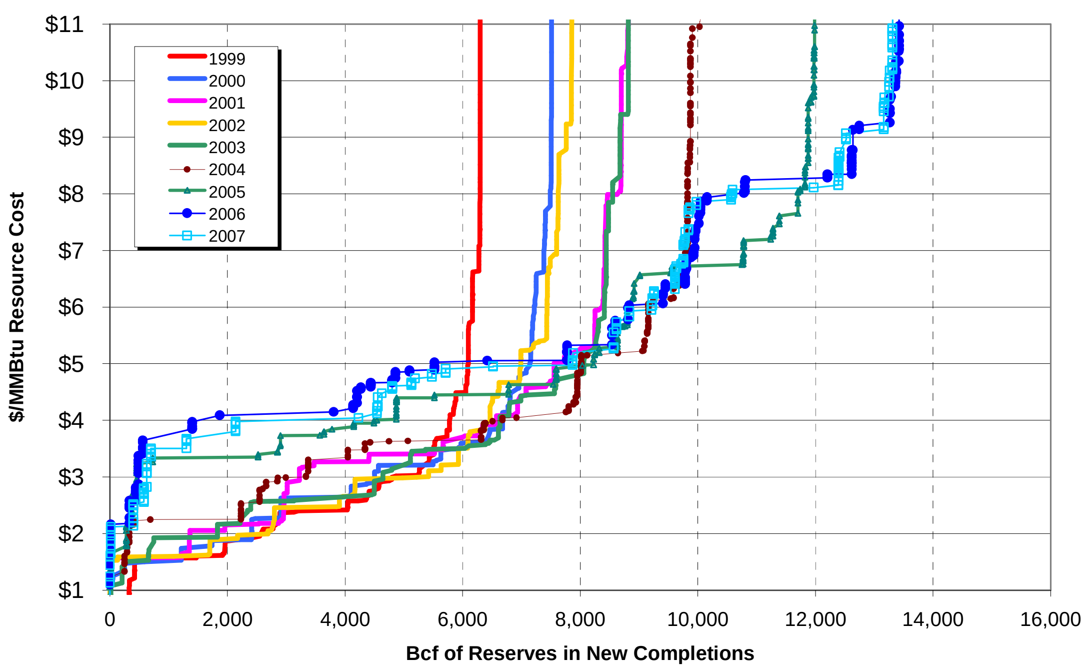


Figure 51 Annual Lower-48 Coalbed Methane Wellhead Cost Curves

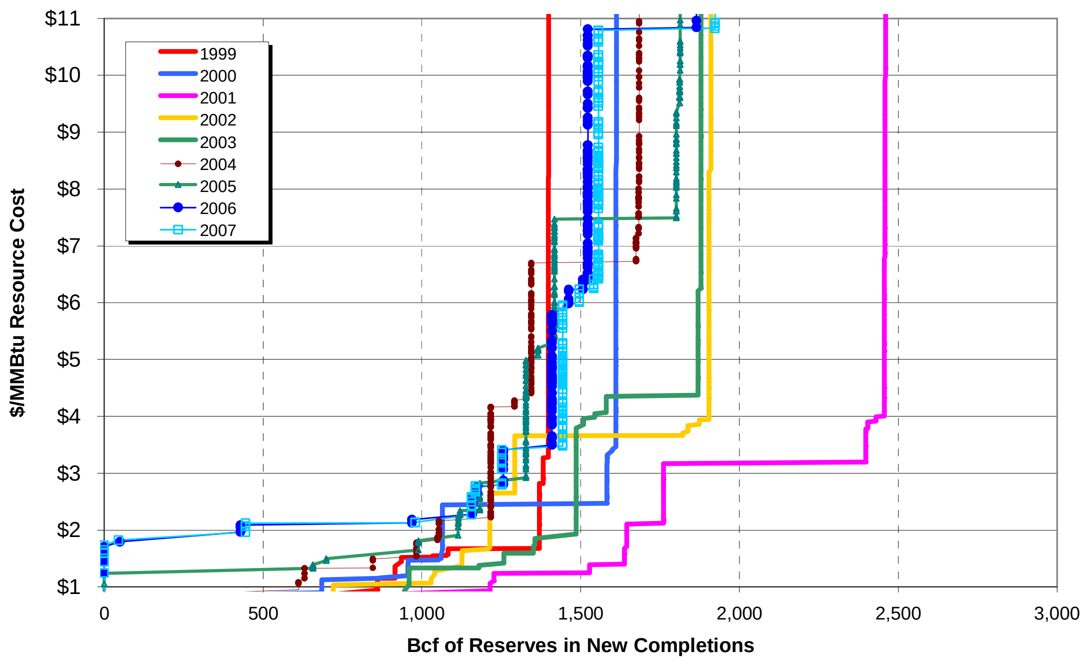


Figure 52 Annual Lower-48 Shale Gas Wellhead Cost Curves

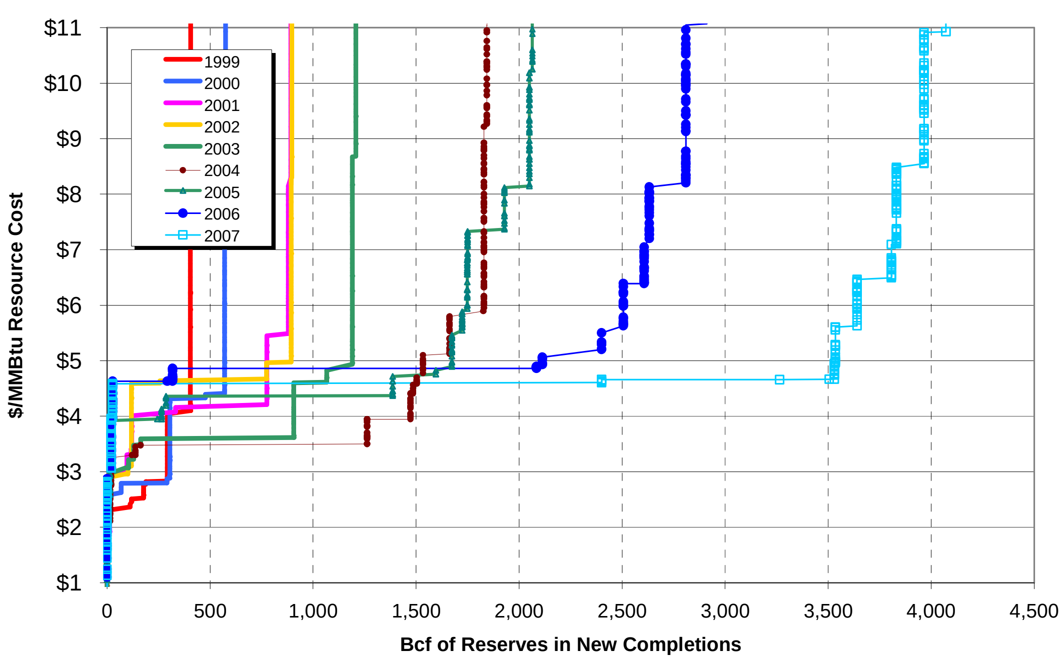
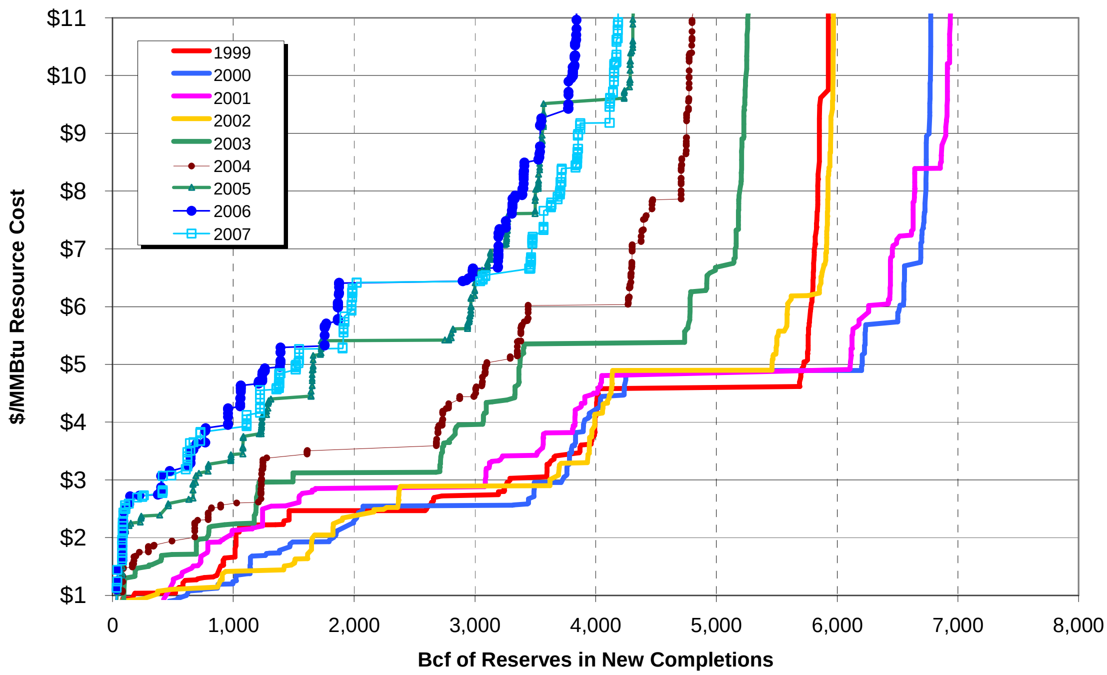


Figure 53 Annual Lower-48 Conventional Wellhead Cost Curves



Tables 28 through 32 summarize the natural gas well finding and development cost and resource costs for the Lower-48 and for the various categories of unconventional natural gas since 1999. Each table shows the annual number of completions, the average recovery per completion, the average finding cost, and the resource cost at the wellhead. Finding costs are defined as the total capital costs incurred in the year divided by the total reserve additions in that year. Finding costs on the table are in units of "Mcfe," or mcf of gas-equivalent. This is a convention used to evaluate costs in which the value of the co-produced natural gas liquids is also included. In developing this measure, the natural gas liquids are converted to an equivalent volume of natural gas.

Table 28 Summary of Finding and Resource Costs - All L-48 Natural Gas Wells

Note: The term Mcfe stands for mcf-equivalent. See text for explanation.

Year	Number of Completions	bcf per Completion	Average Finding Cost ($/Mcfe)	Average Resource Cost ($/MMBtu at wellhead)
1999	13,578	1.04	$1.28	$2.64
2000	18,636	0.89	$1.40	$2.96
2001	23,855	0.80	$1.59	$3.42
2002	20,776	0.81	$1.40	$3.09
2003	21,015	0.82	$1.53	$3.43
2004	23,458	0.79	$1.71	$3.93
2005	27,983	0.75	$2.31	$5.21
2006	31,138	0.76	$2.74	$6.14
2007	31,462	0.79	$2.59	$5.91

Table 29 Summary of Finding and Resource Costs - Tight Gas

Year	Number of Completions	Bcf per Completion	Average Finding Cost ($/Mcfe)	Resource Cost ($/MMBtu at wellhead)
1999	6,571	0.96	$0.92	$2.49
2000	8,456	0.89	$1.08	$2.90
2001	10,643	0.83	$1.34	$3.50
2002	9,486	0.83	$1.16	$3.10
2003	10,432	0.85	$1.28	$3.36
2004	11,672	0.87	$1.48	$3.85
2005	14,862	0.82	$1.99	$5.05
2006	16,974	0.81	$2.42	$6.03
2007	16,468	0.83	$2.33	$5.89

Table 30 Summary of Finding and Resource Costs - Coalbed Methane

Year	Number of Completions	bcf per Completion	Average Finding Cost ($/Mcfe)	Average Resource Cost ($/MMBtu at wellhead)
1999	2,260	0.62	$0.36	$0.96
2000	4,471	0.36	$0.55	$1.43
2001	6,108	0.40	$0.64	$1.57
2002	5,354	0.36	$0.77	$1.87
2003	3,895	0.48	$0.69	$1.67
2004	4,585	0.37	$1.17	$2.63
2005	4,781	0.38	$1.43	$3.14
2006	4,959	0.38	$1.99	$4.12
2007	5,138	0.38	$2.00	$4.20

Table 31 Summary of Finding and Resource Costs - Shale Gas

Year	Number of Completions	Bcf per Completion	Average Finding Cost ($/Mcfe)	Resource Cost ($/MMBtu at wellhead)
1999	875	0.46	$0.81	$3.01
2000	1,248	0.46	$0.95	$3.52
2001	1,812	0.49	$1.28	$4.22
2002	1,855	0.48	$1.40	$4.48
2003	2,064	0.59	$1.19	$3.89
2004	2,228	0.83	$1.37	$3.93
2005	2,824	0.73	$1.79	$4.93
2006	3,234	0.90	$2.07	$5.40
2007	3,539	1.15	$1.93	$5.03

Table 32 Summary of Finding and Resource Costs - Conventional

Year	Number of Completions	Bcf per Completion	Average Finding Cost ($/Mcfe)	Resource Cost ($/MMBtu at wellhead)
1999	3,872	1.53	$1.89	$3.18
2000	4,461	1.52	$1.98	$3.33
2001	5,292	1.32	$2.26	$3.87
2002	4,081	1.48	$1.90	$3.27
2003	4,623	1.15	$2.30	$4.07
2004	4,973	0.98	$2.47	$4.52
2005	5,517	0.88	$3.63	$6.50
2006	5,971	0.84	$4.26	$7.64
2007	6,318	0.82	$3.95	$7.30

7.3 Sensitivity of Costs to Lease Bonus and Royalty Rates

The PLCM analysis carried out in this study is based upon our best current data for well recoveries and costs. One factor that impacts costs is variability in lease costs and royalty rates. Emerging shale plays are characterized by higher lease costs and royalties than those of the past, as operators compete to secure lease positions. In areas with "normal" demand for leasing rights, acreage can be held for a lease bonus of $50 to $100 per acre plus a promise to pay royalties of 1/8 of any oil or natural gas production. Lease costs in some cases have been several thousand dollars per acre, and up to $15,000 per acre or more in prime parts of the Barnett and Haynesville Shale. Competitive royalty rates for new acreage are 1/6, 1/5, or even 1/4 in the Barnett and other hot areas.

7.4 Resource Cost Summary

Gas well resource development costs have been evaluated for the Lower-48 over the period 1999 through 2007. There has been a shift overall to greater reserve additions per year, and to a distribution that includes more additions at higher play level resource costs and less reserves added at lower costs. As industry has made a large scale shift toward development of unconventional natural gas, the underlying cost of U.S. natural gas reserve additions has gone up. In other words, the capital outlay per unit of new reserves is higher, because the gas does not flow to the well without stimulation as is the case with conventional resources. While this implies that long-term prices will remain higher than in previous years, the large resource base means that there is assurance that future natural gas supplies will be adequate.

There are a number of factors that may change in the future that could alter the resource costs in future years. Factors include:

- Improved drilling and stimulation technology

- Improved operational efficiency

- More widespread application of specific technologies where most effective

- Reduced factor costs through experience. Examples include drilling day rates, horizontal drilling costs, stimulation costs, and operating costs.

- Reduced costs brought about by expanded gathering and processing infrastructure

- Better geologic and engineering understanding leading to fewer uneconomic wells. In all unconventional plays, there are geologic complexities that affect well recovery and production economics. Through research and the development of better understanding of the factors controlling production, it is possible to avoid most dry holes or uneconomic wells. It is also possible to customize drilling and stimulation practices to account for geologic variability.

8 OTHER CATEGORIES OF UNCONVENTIONAL GAS

8.1 Oil Shale – Horizontal Drilling (Bakken Shale and Barnett Shale Oil Leg)

Shale formations containing crude oil and associated natural gas are now being developed in the U.S. This type of oil shale is categorized here as "horizontal drilling" oil shale to differentiate it from the truly non-conventional oil shale such as that in western Colorado that requires thermal distillation to recover the oil.

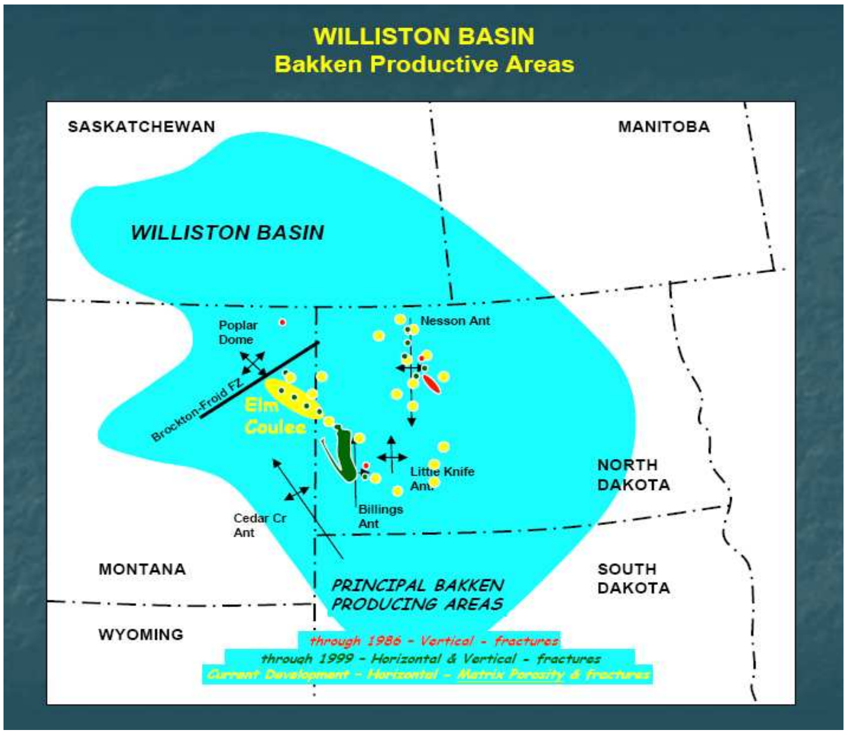
In the Williston Basin of North Dakota and Montana, operators are using horizontal drilling technology to tap the Bakken Oil Shale. This play was assessed earlier this year by the USGS at 3.65 billion barrels of oil and 1.85 Tcf of associated natural gas. A similar play is underway in the oil leg of the Barnett Shale.

In the Bakken, Headington Oil reported that horizontal well productivities range from 200 to 1,900 barrels of oil per day (BOPD) and the associated natural gas ranges from 100 to 900 mcf per day.[107] Industry has focused on Elm Coulee Field, near the Montana/ North Dakota state line (**Figure 54**). The field depth is 8,500 to 10,500 feet. Cumulative oil production through 2005 was 27 million barrels of oil, while the per-well average production rate was 165 BOPD. The productive area in Elm Coulee is about 450 square miles and the play there is expected to recover 225 million barrels of oil and 225 Bcf of natural gas. [108] Wells are reported to have between 4,000 and 23,000 feet of total laterals (including multi-laterals). The completed well cost ranges from $2.5 million to $4.5 million, which includes a stimulation component of $350,000 to $650,000. Resource costs for typical horizontal wells are estimated to be about $31 per barrel of oil equivalent or $5.30 per MMBtu for mid-2008.

[107] Headington Oil, 2006 investor slides (company acquired by XTO).
[108] Headington Oil, ibid.

In May, 2008, Williston Basin Interstate Pipeline Company announced it is planning a 100 mile pipeline to transport natural gas from the Bakken oil play northeast to an interconnect with Alliance Pipeline. [109] The company plans to have the 100-200 MMcfd pipeline operational by 2010.

Figure 54 Extent of Bakken Oil Shale Play



8.2 Oil Shale –Thermal Methods

Oil shale is a fine grained sedimentary rock containing a relatively high percentage of organic matter called kerogen. The kerogen is a type of organic matter can be converted to oil through distillation. The shale must be heated to 500 degrees Centigrade for the conversion to take place. Depending on the quality of the oil shale, between 20 and 50 gallons of oil is generated per ton of rock.

Most of the worldwide oil shale resource occurs in the U.S. As shown in **Table 33,** the U.S. in-place oil shale resource is approximately 2 trillion barrels.[110] Of this amount, approximately 1.5

[109] Reuters, 2008, "Williston Basin Pipeline Announces Plans to Develop Natural Gas Pipeline," May 19, 2008. http://www.reuters.com/article/pressRelease/idUS213500+19-May-2008+BW20080519

[110] Southern States Energy Board, 2006, "American Energy Security," July, 2006.

trillion barrels with a richness of greater than ten gallons per ton is in the Green River formation of Colorado, Utah, and Wyoming. (Richness is a volumetric yield measure indicating the volume of oil that can be extracted). There is also about 200 billion barrels is in the Eastern U.S. in the Appalachian Devonian Shale. The best oil shale deposits in the U.S., those with richness greater than 25 gallons per ton, total 750 billion barrels.

Most industry activity in oil shale occurred in the 1980s in the Piceance Basin of northwestern Colorado. **Figure 55** is a map showing the distribution of oil shale in the U.S.

Table 33 U.S. Oil Shale Resources

	Oil-in-Place Billion Bbls
Total Resource in Place	2,000
Green River Fm portion	1,500
Other than Green River	500
Resource > 25 gal/ton	750

Source: "America's Oil Shale: A Roadmap for Federal Decisionmaking," DOE Office of Naval Petroleum and Oil Shale Reserves, December, 2004.

Figure 55 Map of U.S. Oil Shale Formations

Extraction Technologies

Oil shale resources can be extracted using two basic approaches: mining with surface retorting and in-situ retorting. Oil shale can be mined through room-and-pillar methods or by surface mining.[111] Surface retorting technology has significant technical hurdles. The work in the Colorado oil shales in the 1970s and 1980s established technical but not commercial viability.

With in-situ retorting, the shale is heated in place and the oil is extracted from underground. A major advantage of this method is that is has much less surface impact than mining. Shell Oil has conducted some small scale field tests of the technology using electricity as the heat source. About 250 to 300 kilowatt-hours are required for downhole heating per barrel of oil produced. The company claims potential commerciality of this process in the mid $20 per barrel range.

Natural Gas Produced in Association with Oil Shale

An important aspect of potential oil shale development is the volume of natural gas that is co-produced. Research by Shell Oil indicates that should in situ oil shale development attain a level of activity of 150 acres per year, sustained oil production would be 500,000 barrels per day and the associated natural gas production would be 500 Bcf per year or approximately 1.4 Bcfd.[112]

While essentially all of the co-produced natural gas could be used for on-site generation of power or thermal energy, it would still contribute to overall U.S. energy production and could be displaced by other energy supplies that could be used for extraction. For example, according to RAND, the two million barrels per day of oil extraction production possible by 2020 would co-produce 5.6 Bcf per day or over two Tcf per year. If half of this gas could be diverted to natural gas markets through energy saving technologies and/or fuel substitution, that would add about one Tcf per year to U.S. natural gas supplies.

DOE Oil Shale Program

During the 1980s, the U.S. government managed the Naval Oil Shale Reserves in the Western U.S. When these reserves were opened to development to promote domestic energy production, there was significant industry activity at that time to commercialize oil shale production. In the mid-1980s, oil prices declined and the projects were abandoned. After this, the government transferred the Naval Oil Shale Reserves to the Bureau of Land Management (BLM) and a Native American tribe. [113]

In the Energy Policy Act of 2005 (EPAct), Congress directed the DOE Petroleum Reserves program as the lead office to coordinate the creation of a commercial strategic fuel development program, consisting of oil shale and tar sands.

The following is an excerpt from DOE that describes the scope of the Petroleum Reserves program:

"The Fossil Energy program in oil shale focuses on reviewing the potential of oil shale as a strategic resource for liquid fuels. Activities include reviewing the strategic value of oil shale development,

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[111] Rand Corporation, 2005, "Oil Shale Development in the United States," Rand Corp., Santa Monica, CA.
[112] Rand Corporation, 2005, ibid.
[113] DOE, 2006, DOE Website. http://www.fossil.energy.gov/programs/reserves

public benefits from its development, possible ramifications of failure to develop these resources and related public policy issues. The program is also involved in characterizing the oil shale resource, assessing oil shale technology, summarizing environmental and regulatory issues, and reviewing tar sand commercialization as an analog for oil shale."

Status of Leasing on Federal Land

Currently, five oil shale projects are under review by BLM. An Environmental Impact Statement is underway and commercial leasing could take place by 2008. Shell Oil and Chevron are active in Western oil shale technology development.

In a 2004 report on U.S. oil shale, DOE estimated that oil shale production could achieve a rate of two million barrels per day by 2020, assuming that initial production begins in 2011.[114] That scenario is dependent upon rapid movement toward developing this resource and overcoming many environmental and political hurdles. The report lists air quality, surface and groundwater quality, land reclamation, and ecological effects as being significant hurdles. However, the report concludes that the technologies and procedures to deal with these issues have been well established in the coal mining, refining, and chemical industries. DOE also noted that major uncertainties include potential future changes in environmental regulations and lengthy permitting processes at all levels of government.

In a 2005 report, Rand Corporation estimated that U.S. oil shale production could potentially attain a rate of 3 million barrels per day within a time period of 17 years after the initial decision to develop the oil. This scenario is primarily a technical scenario that assumes such development would be allowed.

Economics of Liquid and Gas Production from Oil Shales

Since the primary product of production from oil shales is oil, the required selling price of any co-produced pipeline-quality natural gas would depend on (1) the value of the oil, (2) the price of the process-heat fuel source, and (3) the capital and operating costs of whatever production technologies prove commercially viable. Cost estimates for oil shale production range from about $25 to over $70 per barrel and usually assume that co-produced natural gas is largely used in the production process itself. Therefore, small volumes of surplus natural gas would be available at a very low price and greater volumes at a substitute-fuel price (based on coal gasified into a crude syngas) of roughly $4.00 per MMBtu and up. Even if a substitute fuel such as coal were unavailable, large amounts of gas would be available at $5.00 to $12.00 per MMBtu (the price range at which the oil could be burned to make methane, instead of the other way around).

In general, there is a paucity of information on the economic viability of liquids production from oil shales in the U.S. The Rand report came to the following conclusions regarding the economics:

> "The estimated cost of surface retorting is high, well above the record-setting crude oil prices that occurred in the first half of 2005. For surface retorting, it therefore seems inappropriate to contemplate near-term commercial efforts. Meanwhile, the technical groundwork may be in place for a fundamental shift in oil shale economics. Advances in

114 U.S. Department of Energy, 2004, "Strategic Significance of America's Oil Shale Resource," DOE Office of Naval Petroleum and Oil Shale Reserves, Washington, D.C., March, 2004.

thermally conducive in situ-conversion may cause shale-derived oil to be competitive with crude oil at prices below $30 per barrel." [115]

According to a DOE report, Shell Oil believes that its in-situ conversion technology can produce transportation fuel at a cost that will be profitable in the $25 per barrel range. [116] However, it has concluded that the economic risk remains high due to the large up-front capital costs.

Table 34 shows ICF estimates of the energy balance and costs for *in-situ* oil shale production using electric heating of the reservoir and today's drilling and construction costs. The oil is contained within the project area (and water influx is controlled) by an underground "freeze wall" around the perimeter of the project. The table characterizes three grades of oil shale. The best grade of shale ("very rich" at 40 gallons per ton) has a resource cost of about $28 per barrel of oil equivalent (BOE). The next best grade of shale ("rich" at 30 gallons per ton) has a resource cost of about $41 per BOE, and the poorest grade ("typical" at 20 gallons per ton) has a resource cost of $79 per BOE.

As shown at the bottom of the table, if gas from the project is used to power the project, about 74.9 Bcf of gas would be marketable annually from a 200 acre oil shale project in a very rich shale. The table shows that 14.5 Bcf would be produced annually from the rich shale example project. The poorest grade of shale has no marketable gas production because the energy needed exceeds gross gas production. Gas production would be possible from the project only if the needed electricity were imported or if another source of energy, such as coal, was used to generate the electricity.

[115] RAND, 2005, "Oil Shale Development in the United States," RAND Corp., Santa Monica, CA.
[116] DOE, 2004, "Strategic Significance of America's Oil Shale Resource, " DOE Office of Naval Petroleum and Oil Shale Reserves, March, 2004.

Table 34 Hypothetical Economics of In-Situ Production of Green River Oil Shales

	Very Rich Shale	Rich Shale	Typical Shale
Gallons oil per ton shale	**40**	**30**	**20**
Depth to Bottom of Shale(ft)	**2,500**	**2,500**	**2,500**
Net Thickness of Shale (ft)	**900**	**900**	**900**
Barrels oil in place per acre	3,136,589	2,352,441	1,568,294
MMBtus oil in place per acre	18,192,214	13,644,160	9,096,107
Heating Well Density (wells per acres)	**25**	**25**	**25**
Initial reservior temperature in Fahrenheit	98	98	98
Desired reservoir temperature in Fahrenheit	**700**	**700**	**700**
MMBtu per acre of heat and heat losses	1,419,203	1,419,203	1,419,203
Kilowatt-hours per acre of heat and heat losses	415,944,487	415,944,487	415,944,487
Energy Efficiency of Heating Process (e.g. generate electricity and heat reservoir with microwaves or resistance heaters)	**0.44**	**0.44**	**0.44**
Input MMBtus of Natural Gas/Other Fuels for Reservoir Heating for 1 Acre	3,234,176	3,234,176	3,234,176
Input Energy for Reservoir Heating as % of Oil in Place	18%	24%	36%
Recovery of oil in place as oil or gas	**80%**	**80%**	**80%**
cf of gas per barrel produced (after heating)	2,800	2,800	2,800
Oil Production per Acre in Barrels	1,675,929	1,256,947	837,965
Gross Gas Production per Acre (MMBtu)	4,833,380	3,625,035	2,416,690
Freeze Wall Temperature Fahrenheit	**25**	**25**	**25**
Freeze Wall Well Spacing in Feet	**50**	**50**	**50**
kWh/Year per freeze well	1,882,906	1,882,906	1,882,906
Capital Costs per Multi-Well Field Project			
Acres per Project	**200**	**200**	**200**
Years to Produce Oil	**4**	**4**	**4**
Number of Heater/Production Wells per Project	5,000	5,000	5,000
Freeze-wall Wells per Project	236	236	236
Lease Acquisition, Geological and Geophysical Costs	$2,063,438	$2,063,438	$2,063,438
Well Costs	$3,125,000,000	$3,125,000,000	$3,125,000,000
Well Equipment	$250,000,000	$250,000,000	$250,000,000
Pro-rated Power Equipment Cost	$712,233,711	$712,233,711	$712,233,711
Pro-rated Chiller Equipment Cost	$32,988,988	$32,988,988	$32,988,988
Site Reclamation	$200,000,000	$200,000,000	$200,000,000
General and Administrative Costs	$648,342,921	$648,342,921	$648,342,921
Total Capital Cost	$4,970,629,057	$4,970,629,057	$4,970,629,057
Gross Recoverable Reserves for Project (MMBtu)	2,910,754,215	2,183,065,661	1,455,377,107
Total Capital Cost as $/MMBtu Gross Recoverable Reserves	$1.71	$2.28	$3.42
Annual Costs and Production per Project			
Capital Recovery	$2,087,324,815	$2,087,324,815	$2,087,324,815
Operations & Maintenance	$249,412,581	$249,412,581	$249,412,581
Total Annual Costs	$2,336,737,396	$2,336,737,396	$2,336,737,396
Gross Annual Production (MMBtu)	727,688,554	545,766,415	363,844,277
Less Fuel for Heating (MMBtu)	161,708,795	161,708,795	161,708,795
Less Fuel for Chilling (MMBtu)	5,081,774	5,081,774	5,081,774
Net Marketable Oil and Gas (MMBtu)	560,897,985	378,975,846	197,053,708
Less Royalty Volumes (MMBtu)	70,112,248	47,371,981	24,631,713
Working Interest Hydrocarbon Sales (MMBtu)	490,785,736	331,603,865	172,421,994
Resource Cost in $/MMBtu	**$4.76**	**$7.05**	**$13.55**
Resource Cost in $/BOE	$27.62	$40.87	$78.60
Assuming Gas is Used First for Process Energy, and then if needed, Oil			
Gross Annual Production Oil (bbl)	83,796,471	62,847,353	41,898,235
Net Annual Marketable Production Oil (bbl)	83,796,471	62,847,353	33,974,777
Gross Annual Production Gas (MMBtu)	241,669,022	181,251,767	120,834,511
Net Annual Marketable Production Gas (MMBtu)	74,878,453	14,461,197	0

8.3 Offshore and Arctic Natural Gas Hydrates

Methane hydrates are ice-like solids in which gas molecules are trapped in water molecules in a cage-like structure called a clathrate. They are found in deepwater and arctic settings. The total assessed in-place potential worldwide is in the range of 700,000 Tcf and may be orders of magnitude higher. [117] The U.S. assessed in-place resource is estimated at 300,000 Tcf. Of that amount, about 21,000 Tcf is in the Gulf of Mexico. There is no current estimate of potential technical or economic recovery; further, there is no commercial production worldwide.

In the U.S., natural gas hydrate deposits are found in onshore Alaska, in the deepwater Atlantic Ocean in Blake Plateau area, and in the deepwater Gulf of Mexico. Hydrates may also exist offshore of the Pacific Northwest. [118]

Figure 56 shows two resource pyramids published in a recent report prepared by Lawrence Berkeley, the USGS, and DOE. [119] The pyramid on the left represents hydrates, and the pyramid on the right represents conventional gas. The top of the hydrates pyramid represents the in-place arctic hydrates that exist at high saturations, in good reservoir rocks, and that are close to producing infrastructure. This volume is estimated at tens of Tcf of gas-in-place. The next level on the pyramid represents arctic hydrates that are in similar geologic settings but are remote from existing infrastructure. That volume is in the hundreds of Tcf in-place. The next level of the resource represents deep water hydrates within sandstone units. The diagram shows this resource to be approximately 1,000 Tcf. As discussed below, however, the Minerals Management Service (MMS) is now estimating Gulf of Mexico sandstone hydrates to be significantly higher, about 6,700 Tcf in-place. The lowest portions of the pyramid, containing most of the gas-in-place, represent the hydrates in very low permeability strata (siltstone and shale) in deep water (labeled on the pyramid chart as non-sandstone marine reservoirs).

Table 35 is a summary of the current USGS/MMS assessment of U.S. natural gas hydrates. The MMS recently completed a new gas-in-place assessment of the Gulf of Mexico, and plans to continue with the assessment of the Atlantic and Pacific and offshore Alaska. [120] Previously, the USGS had completed an assessment of offshore Lower-48 and Alaska areas. The table combines these two assessments, giving a total U.S. volume of 303,000 Tcf.

In their report, the MMS states that hydrates in the Gulf of Mexico can form in water depths more than 400 meters. The thickness of the hydrate stability zone (pressure-temperature regime where hydrates exist) has been modeled in to be in excess of 1,000 meters. The table shows the Gulf of Mexico assessment of 21,000 Tcf in-place. The "sandstone resource" (second column in the table) was assessed at approximately 6,700 Tcf. The sandstone resource is the hydrate volume that is modeled to reside within a stratigraphic section that contains more sand, resulting in greater permeability.

[117] USGS, 2001, "Gas Hydrates – Vast Resource, Uncertain Future," USGS Fact Sheet 021-01, March, 2001.
[118] DOE NETL, 2008, "All About Hydrates," http://www.netl.doe.gov
[119] Moridis, et al, 2008, "Toward Production from Gas Hydrates: Current Status, Assessment of Resources, and Simulation-Based Evaluation of Technology and Potential," SPE Paper 114163.
[120] MMS, 2008, "Preliminary Evaluation of In-Place Gas Hydrate Resources: Gulf of Mexico Outer Continental Shelf," MMS 2008-04, February, 2008.

Figure 56 Natural Gas Hydrate and Conventional U.S. Natural Gas Resource Pyramids

Source: Moridis, et al, 2008 [121]

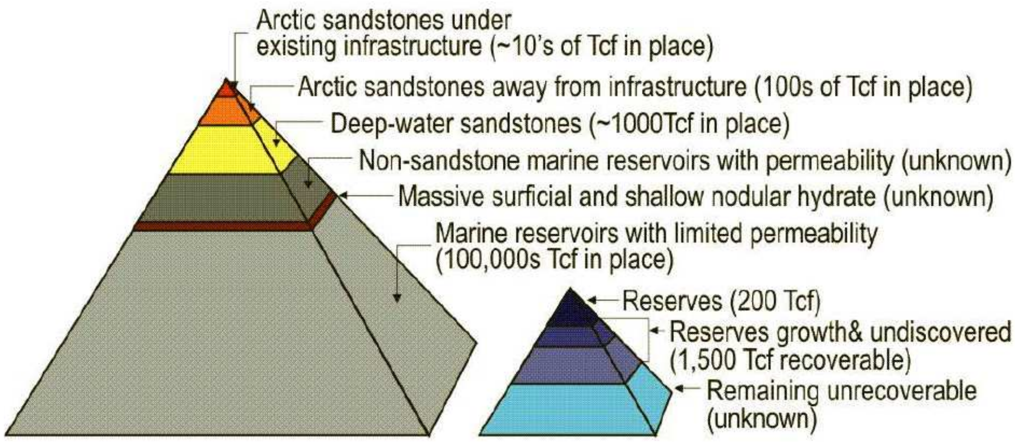


Table 35 Current USGS Assessment of U.S. Natural Gas Hydrate Resource

	Total Gas-in-Place Tcf	Sandstone Only Gas-in-Place Tcf
Gulf of Mexico (MMS, 2008)		
West	4,626	?
Central	11,476	?
East - 1	3,154	?
East - 2	2,187	?
Total	21,443	6,717
Other Than Gulf of Mexico (USGS, 2001))		
Atlantic Offshore	51,831	
Pacific Offshore	61,071	
Alaska Offshore	168,449	
Alaska Onshore	590	
U.S. Total (ICF sum of two volumes)	303,384	

Sources:
USGS, 2001, "Gas Hydrates - Vast Resource, Uncertain Future," USGS Fact Sheet 021-01, March, 2001.

MMS, 2008, "Preliminary Evaluation of In-Place Gas Hydrate Resources: Gulf of Mexico Outer Continental Shelf," MMS 2008-04, February, 2008.

[121] Moridis, et al, 2008, "Toward Production from Gas Hydrates: Current Status, Assessment of Resources, and Simulation-Based Evaluation of Technology and Potential," SPE Paper 114163.

In November of 2008 the USGS announced the initial conclusion that 85.4 Tcf of recoverable hydrates may exist on the North Slope of Alaska.[122] Further analysis including economic evaluation is ongoing.

There has been aggressive international collaboration to study both arctic and subsea methane hydrates. Japan and the U.S. are conducting arctic drilling and research in Canada. In 1998, the first research well was drilled to study methane hydrates in the Canadian Arctic.

The Japanese are researching deepwater hydrate potential. In 1999, the Japanese drilled an offshore deepwater hydrate research well in the Nankai trough. About two years ago, the Japanese announced the delineation of a large deepwater hydrate deposit that lies close to the seabed. [123] This may eventually be the area of the first attempt to produce a deepwater hydrate resource.

In the U.S. this year, a joint industry gas hydrate research project is expected to drill three wells in the deepwater Gulf of Mexico. In addition, the DOE is involved in arctic hydrate research in Alaska with BP. DOE stated that, while long term production tests have not yet been achieved, it is likely that production can be demonstrated by 2020 and commercial production by 2025. [124]

Factors Determining Production from Hydrates

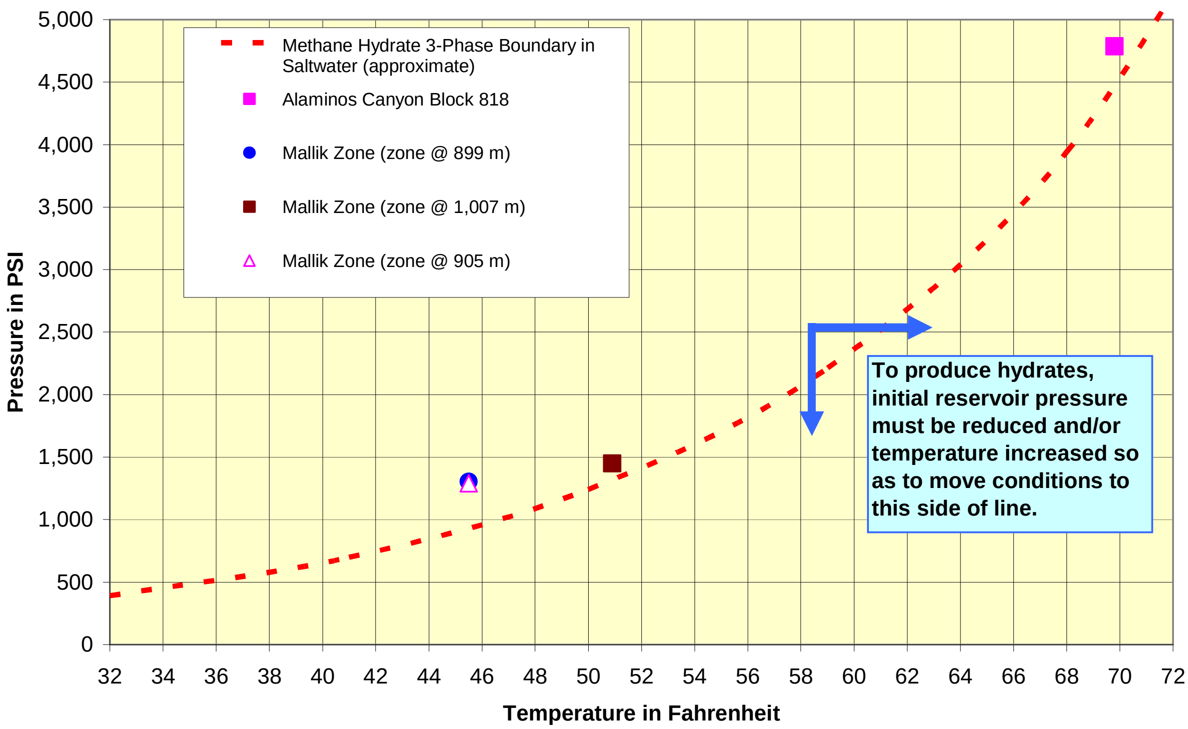
The following factors are necessary for economic production of hydrates:

- Reservoir section with adequate **permeability** so that the dissociated gas can flow to wells
- Reservoir section with adequate **stability** to maintain the position and mechanical integrity of wells and other downhole equipment
- **Thick section of hydrates** so that a large amount of natural gas can be recovered per well
- **High hydrate saturation** relative to total porosity so that a large amount of natural gas can be recovered per well
- Pressure-temperature regime that is **close to the edge of the hydrate pressure-temperature equilibrium** envelope (see discussion below) so that pressures can be dropped and/or temperature raised to cause dissociation of the hydrate into methane and water

[122] *Gas Daily*, November 13, 2008
[123] Oil and Gas Journal, October 16, 2006.
[124] Oil and Gas Journal, May 9, 2008.

The following chart (**Figure 57**) illustrates the pressure-temperature envelope for natural gas hydrates along with examples of measured reservoir conditions in deepwater Gulf of Mexico and Artic settings. The blue arrows illustrate that an increase in temperature or decrease in pressure can move the hydrate out of the stability zone, allowing gas production. Several specific hydrate accumulations are plotted on the chart, showing their relationship to the stability boundary. Hydrates whose initial conditions are closest to the three-phase hydrate boundary pressure and temperature will be the easiest to produce.

Figure 57 Gas Hydrate Pressure-Temperature Envelope



Gas Hydrate Production Economics

Table 36 shows four hypothetical examples of what hydrate production economics might look like based on mid-2008 costs. The first two examples are in the deepwater Gulf of Mexico, representing a fairly thick hydrate-rich sandstone reservoir. [125] Example #1 assumes that hydrate production will require the introduction of artificial heat into the reservoir while Example #2 assumes that pressure reduction alone (from producing free gas in the reservoir and by pumping out water) will be sufficient to produce the hydrates.

Whether or not the introduction of heat will be needed depends on (1) how close the reservoir pressure and temperature conditions are to the hydrate equilibrium point and (2) whether naturally occurring heat energy from surrounding rock will enter the reservoir to compensate for the cooling effect that will take place in the endothermic process of the methane hydrates dissociating into water and methane. Another important factor will be whether reservoir pressure declines can be achieved by producing any free gas or free water. In the case where no free gas or water exists and where artificial heat is needed to initiate pressure decline, the economic calculations assume heat will be applied by electric (microwave or resistance) heaters contained in horizontal heater wells spanning in four directions away from the vertical production wells. The amount of added heat energy was calculated so as to raise the reservoir temperatures 10 ° C approximately 200 feet around the heater well laterals. This heat would melt the hydrates immediately around the laterals and provide a pathway for gas and water to move toward the production well. The remainder of the hydrates further away from the heater well laterals would have to dissociate from pressure declines alone, since heat losses to the surrounding rock outside the reservoir would make artificial heating of all the hydrate reservoir rocks impractical. In all cases, it is assumed that all-new production infrastructure, including a production platform, must be constructed. Where existing infrastructure could be utilized, costs would be lower than the $12.77 to $23.85 per MMBtu wellhead costs shown here.

The second pair of examples is for onshore Arctic conditions, such as the Mackenzie Delta or North Slope of Alaska. [126] Example #3 assumes that artificial heat must be added, while Example #4 assumes that pressure reductions alone will allow the hydrates to be produced. The Arctic wellhead costs are $1.61 to $7.85 per MMBtu and are substantially lower than the deepwater examples due to much lower drilling and development costs.

[125] U.S. DOE, 2008, "New Simulations of the Production Potential of Methane Hydrates." http://www.netl.doe.gov

[126] Moridis, George, et al, 2002, "Numerical Studies of Gas Production from Several CH4 Hydrate Zones at the Mallik Site, Mackenzie Delta, Canada, " Lawrence Berkeley National Laboratory report LBNL-50257, May, 2002.

Table 36 Hypothetical Examples of Gas Hydrate Economics

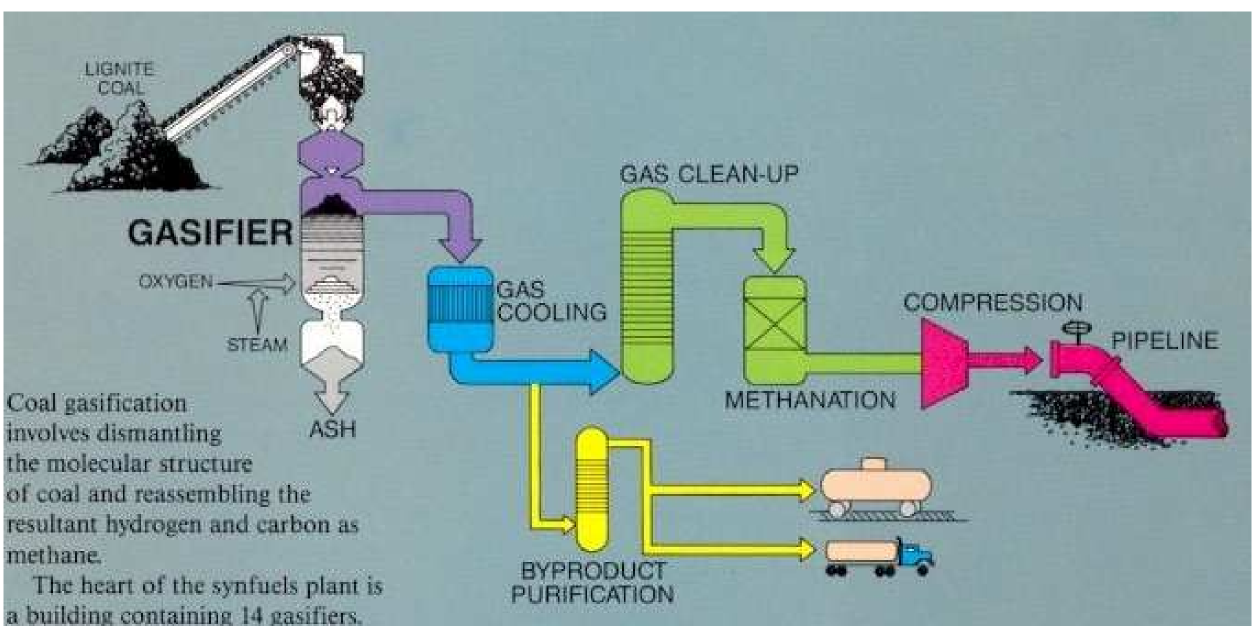
	#1 Deepwater GOM Example: Production Requires Significant Added Heat	#2 Deepwater GOM Example: Production Through Pressure Decline of Free Gas, Water Removal	#3 Onshore Arctic Example: Production Requires Significant Added Heat	#4 Onshore Arctic Example: Production Through Pressure Decline of Free Gas, Water Removal
Water Depth (ft)	**9,000**	**9,000**	**0**	**0**
Bottom of Hydrate Zone (ft below mudline or surface)	**1,530**	**1,530**	**3,608**	**3,608**
Producing Well Measured Depth (ft)	10,530	10,530	3,608	3,608
Drainage Area in Acres per Producing Well	**640**	**640**	**640**	**640**
Hydrate Thickness (ft)	**60**	**60**	**66**	**66**
Porosity	**30%**	**30%**	**28%**	**28%**
Hydrate Saturation	**70.0%**	**70.0%**	**80.0%**	**80.0%**
Cubic Feet of Hydrate-Filled Porosity in Drainage Area	351,267,840	351,267,840	409,656,361	409,656,361
Ratio cf gas to cf hydrate	164	164	164	164
Standard Cubic feet of Natural Gas in Drainage Area	57,607,925,760	57,607,925,760	67,183,643,197	67,183,643,197
Recovery Factor	**60%**	**60%**	**60%**	**60%**
Standard Cubic Feet of Natural Gas Recovered per Producing Well	34,564,755,456	34,564,755,456	40,310,185,918	40,310,185,918
MMBtus of Gas Produced per Producing Well	35,601,698	35,601,698	41,519,491	41,519,491
Number of Heater Wells Laterals per Producing Well	**4**	**0**	**4**	**0**
Heater Well Horizontal Lateral Length (ft)	3,722	-	3,722	-
MMBtus to Raise Reservoir Temperature Around Laterals for 1 Producing Well	865,629	-	904,280	-
Energy Efficiency of Heating Process (e.g. generate electricity and heat reservoir with microwaves or resistance heaters)	0.44	0.44	0.44	0.44
MMBtus of Natural Gas for Reservoir Heating Around 1 Producing Well	1,972,654	-	2,060,735	-
Natural Gas for Reservoir Heating as % of Production	5.5%	0.0%	5.0%	0.0%
Production Life in Years	**15**	**15**	**15**	**15**
kW Electric Generation Capacity for Heating 1 Prod. Well	2,145	-	2,240	-
Barrels Water to be Pumped from Reservoir per 1 Producing Well	46,894,257	46,894,257	54,689,124	54,689,124
kWh Total for Water Pumping, Reinjection	47,597,670	47,597,670	112,331,461	112,331,461
Natural Gas for Water Pumping as % of Production	0.9%	0.9%	1.9%	1.9%
Capital Costs per Multi-Well Field Project				
Number of Production Wells per Project	**16**	**16**	**25**	**25**
Lease Acquisition, Geological and Geophysical Costs	$5,248,000	$5,248,000	$7,075,000	$7,075,000
Production Well Costs	$707,616,000	$707,616,000	$360,800,000	$360,800,000
Heater Well Footage per Producing Well	25,420	-	18,498	-
Heater Well Costs	$1,708,197,120	$0	$1,849,760,000	$0
Production Equipment, Platform Costs, Structures	$1,461,013,780	$1,456,724,470	$106,190,597	$101,709,763
General and Administrative Costs	$582,311,235	$325,438,270	$348,573,839	$70,437,715
Total Capital Cost	$4,464,386,135	$2,495,026,740	$2,672,399,436	$540,022,478
Recoverable Reserves for Project (Mcf)	553,036,087	553,036,087	1,007,754,648	1,007,754,648
Total Capital Cost as $/Mcf Recoverable Reserves	$8.07	$4.51	$2.65	$0.54
Annual Costs and Production per Project				
Capital Recovery	$587,015,081	$328,067,125	$351,389,581	$71,006,703
Operations & Maintenance	$103,687,723	$64,300,535	$60,947,989	$18,300,450
Total Annual Costs	$690,702,804	$392,367,660	$412,337,570	$89,307,152
Annual Gross Production (Mcf)	36,869,072	36,869,072	67,183,643	67,183,643
Less Power Generation Fuel (Mcf)	2,387,922	345,045	4,606,886	1,272,363
Less Compressor Fuel (Mcf)	737,381	737,381	1,343,673	1,343,673
Net Marketable Production (Mcf)	33,743,769	35,786,646	61,233,085	64,567,608
Less Royalty Gas (Mcf)	5,623,961	5,964,441	10,205,514	10,761,268
Working Interest Gas Sales (Mcf)	28,119,807	29,822,205	51,027,571	53,806,340
Resource Cost in $/MMBtu	**$23.85**	**$12.77**	**$7.85**	**$1.61**

Since commercial production of hydrates has never been achieved, the reality of achieving these economic examples is very uncertain. Also, it is important to note that the examples are based on favorable reservoir conditions (high permeability, stable reservoir rock, high hydrate saturations and easily-dissociated hydrates) which will apply to only a small fraction of the total hydrate resource. The economic examples suggest that onshore Arctic production might be the closest to being economically viable, once transportation outlets for the gas exist. The offshore hydrates will be more challenging to develop economically, but might be economic in those instances where the most favorable geologic conditions coincide with an existing conventional gas and oil production infrastructure that could be used to reduce hydrate development costs.

8.4 Aboveground Coal to Methane

Gasification systems convert coal (or other solid or liquid feedstocks such as petroleum coke or heavy oils) into a gaseous syngas (synthetic gas). The most widely used type of gasifier is the *steam-oxygen gasifier* that produces a syngas which is composed predominately of hydrogen (H_2) and carbon monoxide (CO).   This is illustrated in **Figure 58**. The major components of a coal-fueled *steam-oxygen gasifier* include: coal handling equipment, gasifier, air separation unit to make oxygen, gas cooling and clean-up processes, and a power block to make electricity to operate the plant. If the gasifier is designed to produce methane, the facility will also include water-gas-shift to convert some of the CO (plus water) into hydrogen (plus CO_2) and a methanation unit to convert H_2 and CO_2 into methane (plus water). The only commercial gasification plant making methane in the U.S., the Dakota Gasification Plant in North Dakota, is of this type.

Figure 58 Flow Schematic for Dakota Gasification
Source: Dakota Gasification Company

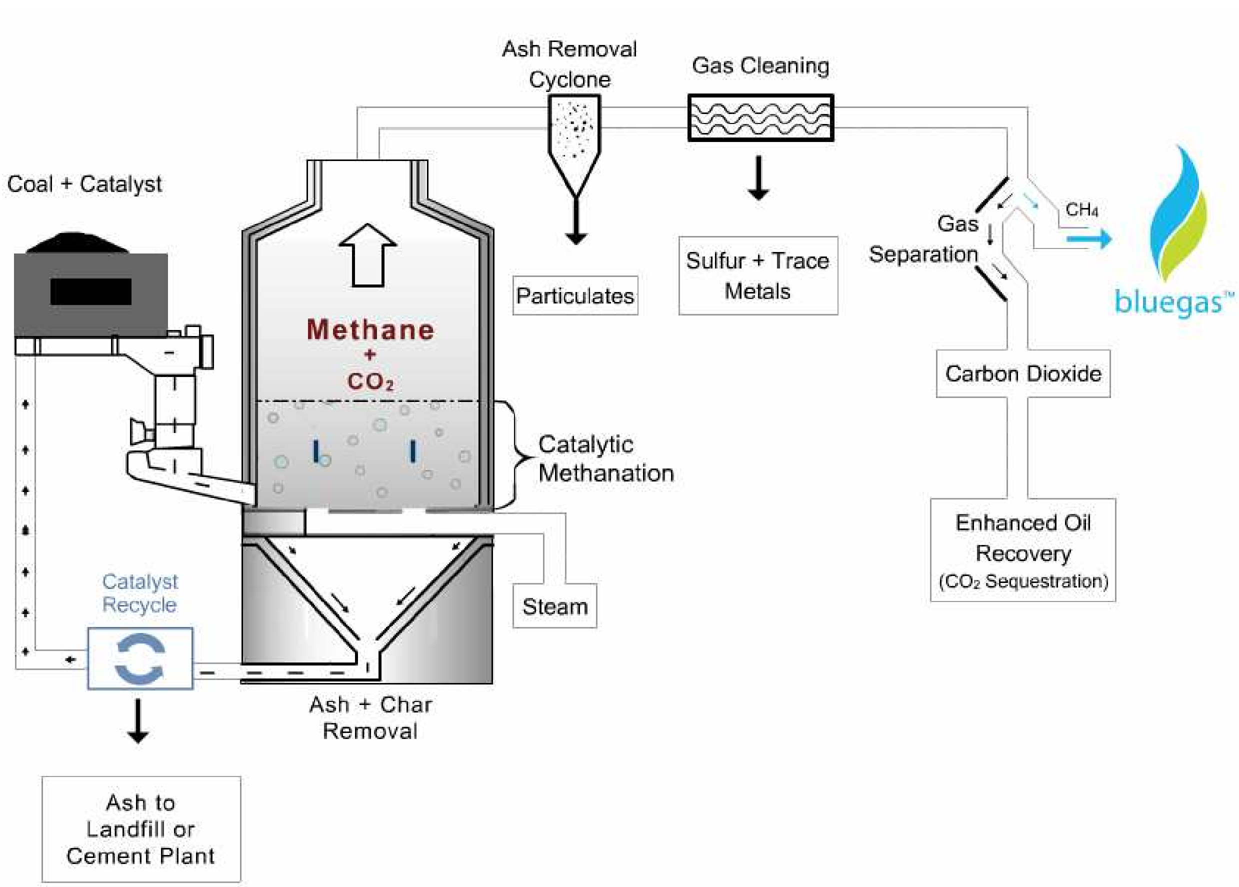


Two other kinds of coal gasification systems that produce methane that have attracted commercial interest are *catalytic gasifiers* and *hydro-gasifiers*. The catalytic process uses a catalyst, such as potassium carbonate or a metal, to endothermically convert coal and steam directly into methane and CO_2. The catalytic process has lower capital costs because it does not require an air separation unit and because separate water-gas shift and methanation steps are avoided. However, the costs of both the catalyst itself and catalyst recovery and recycling must be borne.

GreatPoint Energy of Cambridge, Massachusetts is developing a *hydro-gasifiers* process that they hope to commercialize (**Figure 59**). GreatPoint Energy's technology uses a novel catalyst to "crack" the carbon bonds and transform the coal into methane. By adding a proprietary catalyst to the coal gasification system, GreatPoint Energy is able to reduce the operating temperature in the gasifier so that less expensive reactor components are required. Also, ash removal and slagging problems are avoided thus reducing maintenance requirements and increasing overall thermal efficiency to 65%.

Figure 59 Flow Schematic of GreatPoint Energy Gasification Process

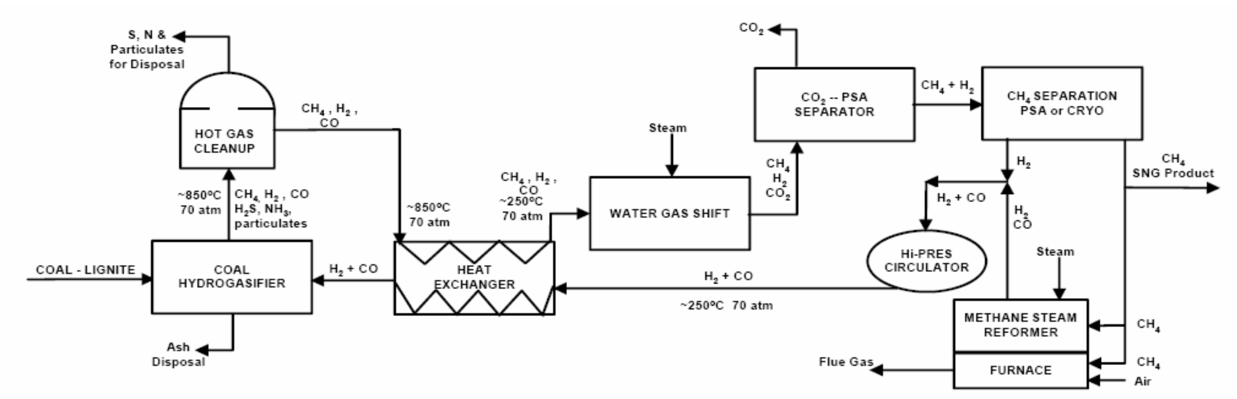
Source: GreatPoint Energy



The *hydro-gasification* process combines hydrogen with coal to exothermically produce methane and carbon monoxide. The carbon monoxide goes through a water-gas shift to produce more feedstock hydrogen. Hydro-gasification does not require an air separation unit or a separate methanation step. However, to obtain sufficient hydrogen for the process, some of the product methane needs to be reformed into hydrogen. This requires a reformer and additional water-gas-shift capacity. HCE, LLC of Oakton, Virginia is hoping to commercialize hydro-gasification to make methane both in aboveground plants and in underground coal seams ("Pumped Carbon Mining"). This is illustrated in **Figure 60**.

Figure 60 Flow Schematic of HCE Hydro-gasification Process

Source: HCE, LLC



Currently Planned Coal Gasification Plants and Expected Gas Production

Table 37 lists the known current and planned coal-methane plants. Coal gasification plants which produce electric power (IGCC), Fischer-Tropsch liquids, methanol, ammonia, and synthetic gas (here, a mixture of hydrogen and carbon monoxide) are excluded. The annual gas production from the nine plants is expected to be more than 400 Bcf per year.

Table 37 Current and Planned Coal to Methane Plants

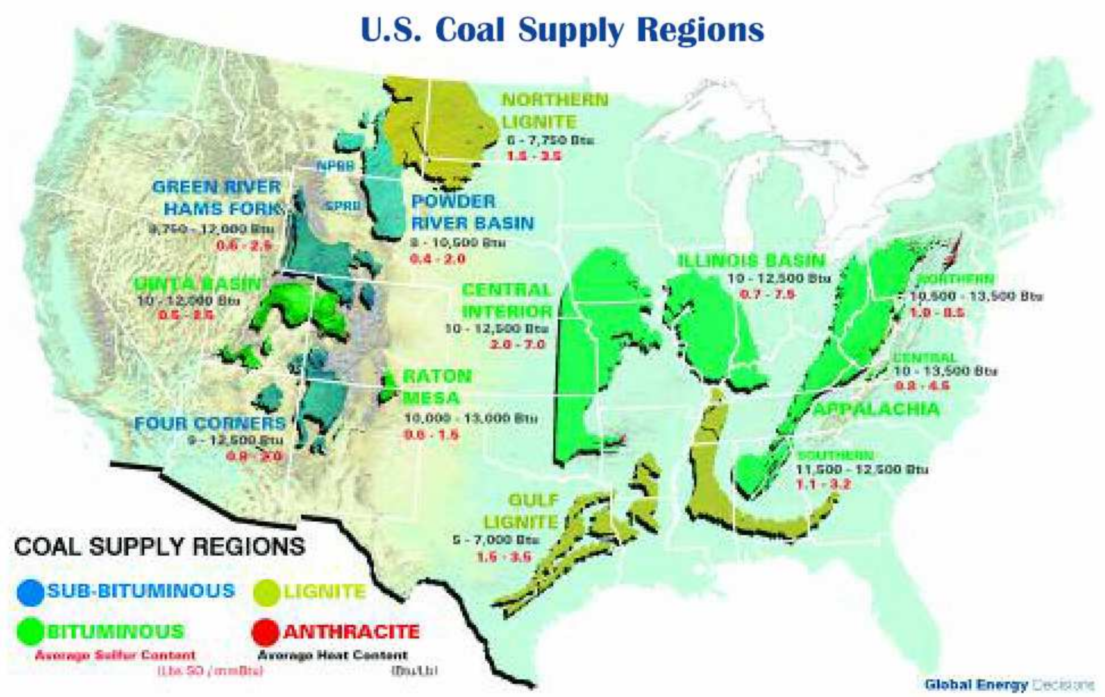
Company	Plant Location	Technology	Project Size	Status
Dakota Gasification Company	Beulah, ND	Sasol Lurgi Dry Ash Moving Bed	62 Bcf/yr	Operational
GreatPoint Energy	Somerset, MA	Catalytic gasifier	Pilot scale	Pilot-scale plant planned
HCE, LLC	TBD	Hydro-gasifier	TBD	Uncertain
Indiana Gasification, LLC	Southwest Indiana	GE Energy Technology -- Coal to syngas to methane, with nickel-oxide catalyst	40 Bcf/yr	Plant startup 2011
Indiana Gasification, LLC	Louisiana	GE Gasification Technology -- Petroleum coke to methane, hydrogen, and methane	TBD	Uncertain
Peabody Energy/ ConocoPhillips	Kentucky	E-GAS (ConocoPhillips) Gasification Process	28 Bcf/yr	Plant startup 2013
Power Holdings of Illinois LLC	Mount Vernon, IL	GE Gasification – coal to SNG	50 Bcf/yr	Plant startup 2009
Secure Energy Systems	Decatur, IL	Siemens SFG Gasification Process – coal to SNG	27 Bcf/yr	Plant startup 2009
Sherritt International Corporation	Camrose, Alberta	Dodds-Roundhill Coal Gasification Project – coal to syngas to hydrogen	117 Bcf/yr of syngas to be refined into 98 Bcf/yr of H2	Plant startup 2011

North American Coal Resources and Estimated Gas Potential

As shown in **Figures 61 and 62,** coal resources of the U.S. Lower-48 and Canada are widely distributed. From east to west, major coal producing regions include Nova Scotia, Appalachia, Illinois Basin, Central Interior, Gulf Coast, Northern Plains, and Rockies (extending far north into British Columbia and Alberta). Generally, Appalachia produces higher ranked coal such as Anthracite and Bituminous. Lower ranked Sub-bituminous coals are produced in areas of the Rockies such as the Powder River Basin of Wyoming. The Northern Plains and Gulf Coast deposits are lignite, which is the lowest ranked coal.[127]

Figure 61 Distribution of U.S. Coal Resources

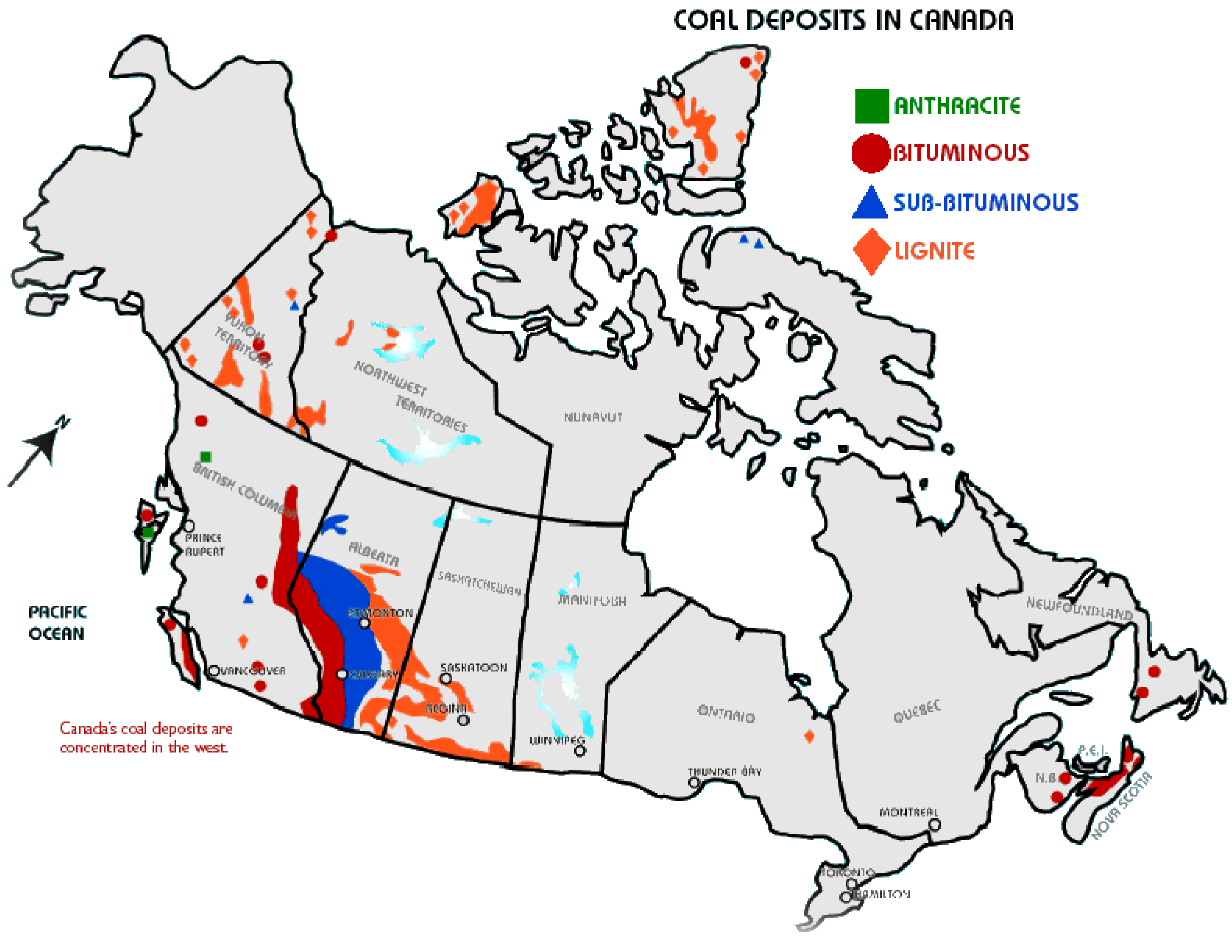
Source: Global Energy Decisions



[127] Coal ranking is based on Btu content per ton.

Figure 62 Distribution of Canadian Coal Resources

Source: The Coal Association of Canada



Assessment of U.S. coal reserves and resources is conducted by EIA and USGS. EIA reports measured or proved reserves, while the USGS uses geological mapping to quantify the unproved portion of the resource.

Table 38 summarizes the assessed coal resources of the U.S. This compilation uses the most recent volumes from EIA for proved reserves, combined with a USGS estimate of undiscovered coal.

Table 38 U.S. Coal Resources (Short Tons) Converted to Methane on and Energy Basis with 50% Conversion Efficiency

Resources	Reserves	Demonstrated Reserves	Billion Short Tons of Coal	Trillion SCF of methane
Identified Resources				
	Demonstrated Reserve Base (0-1,000 ft. deep)			
		Measured (Recoverable Reserves; <0.25 mi.)	267	3,200
		Indicated (0.25-0.75 mi.)	228	2,700
	Total Demonstrated Reserve Base		495	5,900
	Inferred (0.75-3 mi.; down to 6,000 ft. deep)		1,236	14,800
Total identified (measured, indicated, inferred)			1,731	20,700
Undiscovered Resources (>3.0 mi.; down to 6,000 ft. deep)			2,237	26,800
Total Assessed Resources			3,968	47,500

Sources:
Demonstrated reserve base: EIA, 2004, Annual Coat Report, November, 2005.
Inferred and Undiscovered resources: USGS, 1974, USGS Bulletin 1412, 131 p.

Notes:
The current USGS assessment was done with a different assessment. The total assessment for the Lower-48 states is 1,620 billion tons.

Recoverable Reserves of coal total 267 billion tons. This is a subset of the larger *Demonstrated Reserve Base* of 495 billion tons. The *Demonstrated Reserve Base* is that portion of coal-in-place that could potentially be converted to proved reserves. *Recoverable Reserves* are volumes of coal that are accessible and economically recoverable by current mining methods under existing regulations.

Outside of the Demonstrated Reserve Base are less certain categories of coal, including the classifications of "Inferred" and "Undiscovered." In the case of Inferred resources, the coal beds are more than 0.75 miles but less than three miles from existing wells or mines. *Undiscovered Resources* are those that have significant uncertainty and lie in areas greater than three miles from existing wells and mines. The sum of Demonstrated Reserve Base, Inferred, and Undiscovered coal is approximately 4,000 billion tons.

Demonstrated Reserve Base is that portion of the resource base that it likely to be ultimately targeted for mining. The Inferred and Undiscovered portions of the resource represent coal zones that are either too thin or too deep to be realistically targeted. For example, the Undiscovered Resource includes seams up to 6,000 feet deep, while current underground mining is limited to about 2,500 feet. In addition, seams as thin as 14 inches for bituminous and anthracite are included.

If we assume that the Demonstrated Reserve Base of approximately 500 billion tons is the potentially mineable portion of the resource, then the unmineable portion (the remainder of the 4,000 tons discussed above) is at least 3,500 billion tons of coal.

In addition, **Table 38** includes a column for methane production from the coal. The conversion of short tons of lignite and Sub-bituminous coal to methane is calculated on an energy basis. The table assumes 50 percent *conversion efficiency*. Conversion efficiency is a measure of how much energy remains after energy is expended to convert the coal to methane. A conversion efficiency of 60 percent is also reasonable. Assuming 10,000 Btu/lb of coal as mined and 60 percent thermal conversion efficiency, about 12 mcf of methane is produced from each short ton of coal. For scale, current natural gas consumption for the entire U.S. is about 23 Tcf per year.

Project Lead Time

The typical project lead time from conception to bring the plant on-line is around eight years. For example, consider the timeline of Duke's $2 billion IGCC plant in Edwardsport, Indiana. In 2004, Cinergy/PSI (now Duke Energy Indiana) signed a letter of intent with GE Energy and Bechtel Corporation to study the feasibility of an IGCC plant. In November 2007, the Indiana Utility Regulatory Commission granted Duke permission to build the Southwestern Indiana coal gasification plant in Edwardsport. At that time, Duke anticipated that construction would begin in early 2008 and be complete by 2012.

Environmental Impacts of Aboveground Coal Gasification

Using coal to produce methane will have a number of environmental consequences. Coal mining itself causes numerous environmental issues, ranging from widespread land disturbance, soil erosion, dust, biodiversity impacts, and waste piles, in addition to subsidence and abandoned mine workings. Once coal has been extracted, it needs to be moved from the mine to the power plant or other place of use.

The main pollutants resulting from conventional combustion of coal are sulfur oxides (SO_x), nitrogen oxides (NO_x), particulates, CO_2, and mercury (Hg). In contrast, the methanization processes considered here are conversions rather than combustion processes, which is more effective at reducing criteria pollutants than existing pollution control technologies applied to combustion products. These methanization processes produce ash, particles, sulfur, and trace metals in solid form, in addition to CO_2. Unlike combustion, the CO_2 is produced in a stream with at least 95 percent concentration.

Potentially, the most significant future issue for coal methanization is CO_2 emissions. For each short ton of coal consumed, around 1,500 lbs of CO_2 will be produced. Putting it another way, the CO_2 emissions are about three kg CO_2 per kilogram of methane produced. These numbers do not include CO_2 emissions from the diesel-powered equipment to mine and transport the coal from the mine to the gasification plant.

8.5 Underground Coal Gasification

Underground coal gasification (UCG) is a technology that converts energy in underground coal to a combustible gas that can be used for power generation and as a feedstock for refined fuels and chemicals. The process involves the drilling of air injection wells and gas production wells. Upon injecting air or oxygen through the injection well, the coal seam reacts to produce a relatively low quality, combustible gas. The raw gas stream contains methane, carbon monoxide, hydrogen, and carbon dioxide, along with other components. The UCG process is halted when injection of air or oxygen ceases.

Energy Products

According to the DOE, UCG can be deployed to produce the following products: [128]

- Synthetic natural gas
- High efficiency electricity through IGCC configuration
- Liquid fuels using the Fischer-Tropsch process [129]
- Hydrogen

Technologies

Figure 63 is an illustration of a typical layout for UCG. The following text from the UK Department of Trade and Industry describes the process of UCG:

> "In the UCG process, the combustible gas is produced by the partial, in-situ combustion of an underground coal seam by a mixture of oxygen (or oxygen-enriched air) and water, the reactants. The oxygen (or oxygen-enriched air) and water are injected from the surface via an injection well, and the resulting coal gasification occurs in a chamber, the gasification reactor, within the coal seam. The product gas is extracted via a production well. Together, the injection well and injection facilities, the production well and production facilities and their associated gasification reactor compromise one UCG module." [130]

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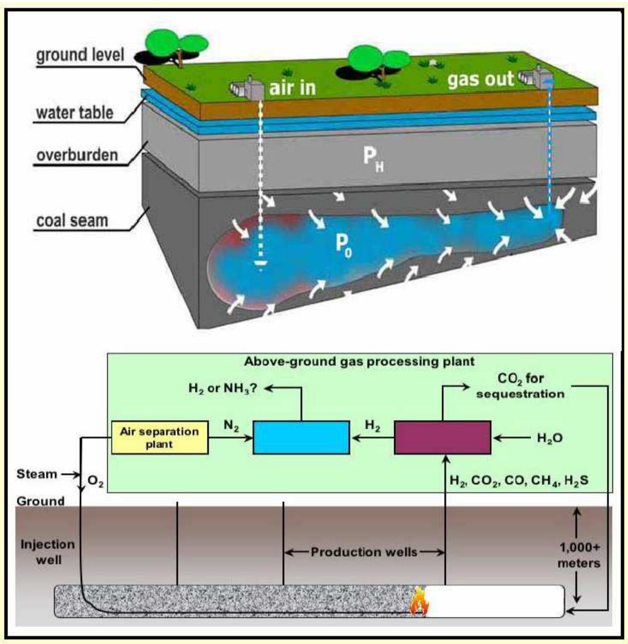
[128] DOE, 2005, "Underground Coal Gasification in the USA and Abroad," testimony by Dr. Julio Friedmann, Lawrence Livermore Laboratory, to Senate Foreign Relations Committee. https://co2.llnl.gov/pdf/UCG_CongTest.pdf

[129] DOE, 2008, "Fischer-Tropsch Fuels," http://www.netl.doe.gov/publications/factsheets/rd/R&D089.pdf

[130] UK Department of Trade and Industry, 2004, "Review of Environmental Issues of Underground Coal Gasification," DTI Report R272, November, 2004.

Figure 63 Approach Used in Underground Coal Gasification with Vertical Wells

Source: UK Department of Trade and Industry



The raw gas produced in UCG must be treated to render it useful as a fuel or chemical feedstock. Treatment involves dehydration and the removal of CO_2 and other impurities. The waste gas streams must be disposed. For example, the separated CO_2 may be injected into underground reservoirs for sequestration. It may also be used in a process called Enhanced Coalbed Methane production, in which the CO_2 is injected into a coal seam, resulting in the production of incremental coalbed methane.

UCG has been demonstrated or implemented in several countries. [131] Several large scale plants have been developed in the Former Soviet Union and have been used for heating and power production. The approach used in the Former Soviet Union involved vertical wells and relatively shallow coal. However, it is now believed that given technology advances, the future market potential market would be in deeper, unmineable coals. [132]

In addition to accessing deep coals that would never be mined, UCG has the potential to be an environmentally friendly method of extracting energy from coals that may be within mining depths, but in areas where mining is infeasible or environmentally unacceptable.

[131] U.K. Department of Trade and Industry, 2006, "Review of the Feasibility of Underground Coal Gasification in the UK." http://www.dti.gov.uk/energy/page19148.html
[132] U.K. Department of Trade and Industry, 2004, ibid.

U.S. Experience with UCG

According to DOE, UCG research has been conducted in the U.S. for about 60 years. Up until the 1990s, there were 33 field trials conducted by DOE and the National Laboratories. The program was considered a success, but due to energy price declines in the 1980s, the program did not achieve commerciality.

Environmental Issues with UCG

The most significant environmental risks of UCG involve groundwater contamination through the escape of gases and leachate migration as liquid. [133] Leachate is a contaminated liquid that results when water collects contaminants as it moves through a solid substance, such as mine tailings, or in the case of UCG, the underground coal seam. However, these risks can be minimized through proper site selection and process control.

In terms of site selection, deeper coal seams have much less potential to damage shallow aquifers. Groundwater contamination in two U.S. test sites occurred in shallow coals. The geological characteristics of the coal and surrounding site are also important.

In terms of process control, the most important factor is to keep the pressure within the reactor lower than that of the surrounding strata, so as to prevent outward fluid migration. Such outward migration could potentially contaminate the groundwater. Also, after a reactor is shut down, venting must be done properly.

Directional Drilling Approach

Over the past ten to fifteen years, advances have been made with a method in which an injection well is drilled horizontally through the coal seam. The air injection point can be moved up the borehole through time, such that a high percentage of the coal is converted with just one well. Multiple, branched horizontal wells are envisioned. It is likely that this is the method that will eventually be used for deeper seams, but no commercial scale projects of this type have been developed. According to the British Department of Trade and Industry (DTI), around 20 coal wells would be required to develop a 300 MW power station.

Economics of Coal Gasification

Estimated 2008 capital costs for various technologies to convert coal to synthetic natural gas (methane) are shown in **Table 39**. The first three options are for entirely aboveground plants, while the last two options are for underground gasification combined with aboveground processing. Costs in this table represent estimated mid-2008 costs for processing equipment and drilling costs for underground options. Note that there is no underground option for catalytic gasification since there would be no practical way of recovering the catalyst from underground reaction chambers.

The estimated cost per unit of substitute natural gas (SNG) for each technology is shown in **Table 40.** Substitute natural gas made from coal in aboveground gasification plants is a proven technology, but its high costs have limited its application in the U.S. to a single commercial plant. Cost estimates for large gasification plants making 150 MMcfd of methane range from $7.61 to

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[133] Leachate is a contaminated liquid that results when water collects contaminants as it moves through a solid substance, such as mine tailings, or in the case of UCG, the underground coal seam.

$8.97 per MMBtu at current cost factors including the run-up in construction cost of 74 percent for all large-scale energy projects experienced from 2004 to mid-2008.

Although UCG has been applied in a very limited scale for several decades outside the U.S., it should be considered an immature technology for which considerable operating experience will be needed before it is commercialized on a large scale. As with aboveground gasification, the final fuel product from the gasified coal can be the crude syngas (carbon monoxide and hydrogen primarily are the fuels), hydrogen, or methane. The costs estimated for methane made from UCG vary widely based on the drilling depth of the coal and coal seam thickness. For a 2,000 feet deep coal bed with a 50 foot seam thickness, the cost of methane would be in the range of $5.61 to $6.28 per MMBtu for a 150 MMcfd facility. About one-third of the capital cost is for wells that would be drilled throughout the 30-year life of the facility. Although the present-value capital cost for underground gasification (with aboveground gas processing and methanation) would be about the same as aboveground gasification, the per-unit costs are lower because the mining and transport costs of the coal are not incurred. However, the cost estimates shown here assume that the typical royalty to the landowner and severance taxes to the state must be paid for the coal gasified underground. These royalty and tax costs could be reduced through policies designed to encourage the technology.

The bottom part of the table shows how a greenhouse gas (GHG) control program might affect SNG economics. For example, at a GHG allowance price of $20 per metric ton of CO_2, the cost per MMBtu for SNG would increase by $1.11 to $2.16 per MMBtu. The uncertainty about whether or how GHG control might be implemented in the U.S. creates an economic risk that discourages SNG plant development.

Table 39 Capital Costs of Substitute Natural Gas Options (150 MMcfd Capacity)

Source: ICF Analysis

(million 2008 dollars)

Location:	Above Ground	Above Ground	Above Ground	2,000 ft. Underground 50 ft. Seam	2,000 ft. Underground 50 ft. Seam
Technology:	Steam-Oxygen Gasification, Shift & Methanation	Catalytic Gasification to Methane	Hydro-gasification to Methane	Steam-Oxygen Gasification, Shift & Methanation	Hydro-gasification to Methane
Coal Handling/ Drying	$87.3	$89.6	$83.5		
Gasifier	$367.8	$388.8	$331.8		
Wells, etc. for Underground Chambers				$846.9	$803.8
Air Separation	$165.8			$215.2	
Sulfur Removal/Recovery	$141.3	$147.2	$98.1	$158.8	$130.7
Water Gas Shift	$49.2		$37.3	$49.3	$42.7
CO2 Removal, Compression	$114.2	$97.1	$83.2	$123.8	$95.1
H2, CH4 Separation			$28.3		$32.3
Methanation	$145.4			$145.4	
Steam Methane Reformer			$268.8		$307.3
Heat Exchanger	$26.5	$26.7	$18.2	$29.7	$20.8
Water Treatment	$28.3	$28.7	$27.2	$26.3	$31.0
Balance of Plant	$92.3	$63.8	$80.1	$66.0	$58.5
Total Installed Cost	$1,218.1	$841.9	$1,056.4	$1,661.3	$1,522.2
Overhead (11%)	$134.0	$92.6	$116.2	$182.7	$167.4
Fees (6%)	$73.1	$50.5	$63.4	$99.7	$91.3
Contingency (12%)	$146.2	$101.0	$126.8	$199.4	$182.7
Working Capital	$69.4	$61.8	$66.1	$62.4	$60.4
Total Capital	$1,640.7	$1,147.9	$1,428.9	$2,205.5	$2,024.1
Total Capital Cost ($/Mcfd Capacity)	$10,938	$7,653	$9,526	$14,703	$13,494

- The underground processes described above are less efficient compared to their aboveground counterpart because:
    - Chemical reactions are not as controlled (e.g. more coal is converted directly to CO_2 in the oxygen-steam gasification step).
    - Energy must be used to compress and move fluids to the underground reaction chamber and back to the surface.
    - There are thermal losses to the ground through the wells and through the chamber walls.

- Some of the fluids are lost as they pass trough the permeable chamber walls.
- Also, the hydrogasification processes tend to produce less CO_2 compared to the other processes.

Table 40 Per-Unit Costs of Substitute Natural Gas Options

Source: ICF Analysis.

(million 2008 dollars)

Location:	**Above Ground**	**Above Ground**	**Above Ground**	**2,000 ft. Underground 50 ft. Seam**	**2,000 ft. Underground 50 ft. Seam**
Technology:	**Steam-Oxygen Gasification, Shift & Methanation**	**Catalytic Gasification to Methane**	**Hydro-gasification to Methane**	**Steam-Oxygen Gasification, Shift & Methanation**	**Hydro-gasification to Methane**
Annual Costs ($ million)					
Capital	$203.7	$142.5	$177.4	$202.1	$183.2
Coal	$135.9	$148.1	$116.0	$16.8	$15.7
Water	$0.3	$0.7	$0.5	$0.2	$0.6
Catalyst	$5.1	$17.8	$0.0	$5.1	$0.0
Direct O&M	$49.2	$34.4	$42.9	$42.5	$38.2
Taxes & Insurance	$41.0	$28.7	$35.7	$35.4	$31.8
G&A, Overhead	$18.0	$12.6	$15.7	$15.6	$14.0
Total	$453.2	$384.8	$388.3	$317.5	$283.6
Annual Methane Sales (MMBtu)	50,550,000	50,550,000	50,550,000	50,550,000	50,550,000
Cost per MMBtu of Methane Sales					
Capital	$4.03	$2.82	$3.51	$4.00	$3.62
Coal	$2.69	$2.93	$2.30	$0.33	$0.31
Water	$0.01	$0.01	$0.01	$0.00	$0.01
Catalyst	$0.10	$0.35	$0.00	$0.10	$0.00
Direct O&M	$0.97	$0.68	$0.85	$0.84	$0.76
Taxes & Insurance	$0.81	$0.57	$0.71	$0.70	$0.63
G&A, Overhead	$0.36	$0.25	$0.31	$0.31	$0.28
Total	**$8.97**	**$7.61**	**$7.68**	**$6.28**	**$5.61**

Metric tonne CO2 per Mcf Methane	0.09	0.07	0.06	0.11	0.07
Added costs for CO2 $/tonne	**Cost Added per MMBtu due to CO2 Allowance Costs**				
$10	$0.94	$0.72	$0.56	$1.08	$0.70
$20	$1.89	$1.44	$1.11	$2.16	$1.39
$30	$2.83	$2.16	$1.67	$3.24	$2.09
$40	$3.77	$2.88	$2.22	$4.32	$2.78
$50	$4.72	$3.60	$2.78	$5.40	$3.48

Note: Coal prices are assumed to be $40 per short ton ($1.71/MMBtu) delivered to above-ground plants.

Financial Incentives for Coal Gasification

In EPAct 2005, Congress illustrated its concern about energy security and sustainability by committing the U.S. government to spend billions of dollars on clean coal technologies, including gasification. The commitment of financial resources consisted of a combination of tax credits, direct grants, and loan guarantees for existing, under development, and newly proposed clean coal and gasification projects. Some of the key provisions of EPAct include the following:

EPAct enables DOE to provide $200 million annually for nine years, from 2006 to 2014, in the form of loan guarantees, loans, and direct grants, to gasification and other clean coal project developers for a total of $1.8 billion. Of this amount, at least 70 percent must be used for gasification projects.

There are 'carve-outs' for specific types of projects to receive direct grants. Portions of the funds must be allocated to projects in the Upper Great Plains, Alaska, and the Western U.S. A minimum of five of these projects must be petroleum coke projects.

EPAct established tax credits for up to $1.3 billion for coal gasification. Of these amounts, up to $800 million is for IGCC projects; the remaining $500 million is for other advanced coal-based projects. The tax credit for gasification projects for any year is 20 percent of the qualified investment, while the credit for other advanced coal-based projects is 15 percent. In November, 2006, the Secretary of Energy awarded $1.0 billion of tax credits for nine projects. [134] Five of the projects will use advanced gasification to convert coal to electricity and the other four will use gasification for industrial applications.

There is a three-year period from the date of enactment within which to apply for these incentives, after which there is a two-year "proof period" in which the applicants must validate the claims, and within which the government can reduce or remove the incentives.

EPAct provides $85 million for research and development at three specific universities from 2006 through 2010.

Provisions under the Clean Air Coal Program are aimed to increase the efficient and economic use of energy to promote national energy security, diversity, and environmental performance. Authorized appropriations under this provision total $2.5 billion from 2007 to 2013 for new projects, and $500 million from 2007 to 2011 for projects that increase environmental performance at existing plants.

Through the loan guarantee program and the timing requirements, the EPAct establishes commitments in meeting project milestones and financial requirements from project developers. While EPAct demonstrated the DOE's government's commitment to clean coal development, the U.S. Congress has not provided the complete funding authorization needed to follow through on this commitment.

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[134] Coal Utilization Research Council, http://www.coal.org/pdf/TaxIncentives.pdf

In addition to EPAct, the U.S. federal government has been pursuing a number of other clean coal and conversion initiatives. For example, DOE's original FutureGen program was designed to create the first zero emission powerplant that will produce both electricity and hydrogen. However, because of the increase in projected costs, in 2008 DOE decided to restructure FutureGen to make more modest contributions to several power plants with carbon sequestration rather than a large financial contribution to a single project. The details of this revised program are still being worked out.

In addition to these federal initiatives, states and corporations are also moving ahead with clean coal and conversion programs. For example, Arch Coal and DKRW Advanced Fuels, LLC are developing a 13,000 barrel per day of ultra-low sulfur diesel coal-to-liquids (CTL) project in Medicine Bow, Wyoming.

In order to gain the maximum benefit from clean coal and conversion projects, federal and state governments and private corporations have also been pursuing carbon capture and sequestration projects. For example, DOE's proposed 2008 budget includes $79 million for the validation phase of the Carbon Sequestration Regional Partnership and initial work on four sequestration field tests.

Additional incentives for carbon sequestration for power, synthetic natural gas and coal-to-liquids plants have been proposed as part of several GHG legislation proposals. One common idea is to provide "bonus allowances" to facilities that sequester carbon dioxide, particularly in the early years of the regulatory program. The intent is to provide a financial incentive so that the carbon capture and storage technologies can be proven and costs can be reduced through improved understanding.

8.6 Landfill Gas

Landfill methane is generated by the decomposition of organic waste in anaerobic (oxygen-deprived) conditions at municipal solid waste (MSW) disposal facilities, commonly known as landfills. Of all the anthropogenic (human-caused) sources of methane emissions in the U.S., landfills account for the most generation from a single source category—25 percent of the total in 2004. [135] Besides the composition of the waste itself, the amount of methane generated by a landfill over its lifetime is dependent upon the quantity and moisture content of the waste as well as the design and management practices of the facility. Landfills with more waste deposited in them will typically produce more gas over time than those with less waste. Other factors aside, landfills in drier regions will not produce as much gas as those in areas that receive average or better than average precipitation, as moisture is a necessary component in decomposition. The gas generation potential of a landfill is basically "fixed" based on the facility's size and other attributes and the climate in which it is located. Significant generation of landfill gas generally begins about one to two years after waste disposal and continues for ten to 60 years,[135] depending on landfill conditions.

For the purposes of discussing landfill gas generation, MSW disposal sites can be categorized as one of four types: open dumps, sanitary landfills, sanitary landfills re-circulating leachate, and

[135] US EPA, US Emissions Inventory 2006, *Inventory of United States Greenhouse Emissions and Sinks: 1990-2004*, April 15, 2006, http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2006.html

bioreactors. Biogas from waste can be generated by open dump sites, but to a much lesser extent than the other types of landfill generation. Open dumps in the U.S. are typically smaller than landfills and do not have an impermeable lower liner or cap installed or other structural qualities of sanitary landfills that help facilitate the anaerobic conditions necessary for gas generation. Modern sanitary landfills are required to include safeguards in their design and operation to protect the environment, such as liners, leachate collection, and compaction and cover.[136] Leachate is the liquid waste result of water percolation downward through the waste. Some U.S. landfills collect and re-circulate leachate throughout the waste mass to (1) handle this by-product of landfilling that requires collection and disposal itself, and (2) speed up decomposition, thereby reducing volume, creating more airspace for additional waste, and extending the life of the landfill. This process of re-circulating the leachate can intensify the generation of landfill gas; no more gas is created by the landfill than there would have been without the re-circulation, rather the gas is just created sooner. There are different subtypes of bioreactors, but, in general, a bioreactor is considered to be a landfill that injects liquid and/or air in a controlled manner into the waste mass to "accelerate or enhance biostabilization of the waste." [137]

Landfill gas excluding water content is basically composed of roughly 50 percent methane and 50 percent carbon dioxide. However, the gas is typically saturated with moisture and contains less than one percent non-methane organic compounds (NMOCs). Minute amounts of nitrogen, oxygen, and hydrogen and trace amounts of inorganic compounds, such as hydrogen sulfide which has a strong odor, are also found in landfill gas. [138] At exit from a facility, landfill gas is generally between 95 and 100 degrees Fahrenheit.

Approximately 3,200 cubic feet of landfill gas is produced per ton of waste over the waste's 20 or more years of decay[139]— this generation peaks around two years after the waste's placement and declines thereafter. As a rule of thumb in the landfill gas industry, one million tons of waste in-place in a landfill will generate 300 standard cubic feet per minute (scfm) of landfill gas at any given point in time during that waste's productive period. This is enough to generate approximately 0.8 megawatts (MW) of electricity using available technology.

The higher heating value (HHV) of methane is 1,012 British thermal units per standard cubic foot (Btu/scf).[140] Landfill gas that is 50 percent methane would therefore have a heating value of about 506 Btu/scf. Traditionally, EPA has used the higher heating value of fuels when developing regulations and when communicating environmental information. Due to varying compositions of landfill gas at different landfills, measured heating values can range from 350 to 600 Btu/scf.

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[136] US EPA, Office of Solid Waste Web site, 2006, http://www.epa.gov/epaoswer/non-hw/muncpl/landfill/sw_landfill.htm

[137] US EPA, Office of Solid Waste Web site, 2006, http://www.epa.gov/epaoswer/non-hw/muncpl/landfill/bioreactors.htm

[138] US EPA, Landfill Methane Outreach Program (LMOP), *Frequent Questions on Landfill Gas and How It Affects Public Health, Safety, and the Environment*, 2006, http://www.epa.gov/lmop/faq-3.htm

[139] US EPA, AP 42, Fifth Edition, Volume I, Chapter 2: Solid Waste Disposal, January 1995, http://www.epa.gov/ttn/chief/ap42/ch02/index.html

[140] *Chemical Engineers' Handbook*. John H. Perry, ed. McGraw-Hill Book Company: New York, 1963, Page 9-9.

Characterization of U.S. Landfills

Operational U.S. landfills have decreased in number steadily over the past 15 to 20 years. In 1988, there were over 7,900 U.S. landfills operating. Recent reports put the number of operating landfills between 1,600 and 1,800. [141] However, average landfill size is increasing. Large, regional landfills are becoming more common while smaller, localized landfills are filling up and closing down. The result is that overall landfill capacity in the U.S. has remained relatively constant. [142]

Approximately 249 million tons of MSW (including residential and commercial waste, organics, tires, and other wastes that are not industrial, construction and demolition, agricultural, or imported) were deposited in landfills in 2005 alone. [143] The amount of waste estimated to have been in-place 30 years or less in the year 2004 was approximately 6 billion tons. This subset of waste (representative of open and closed landfills) was expected to contribute about 90 percent of the landfill gas generated in 2004. [135]

All landfills are not considered to be prime candidates for landfill gas energy recovery due to their size, geographic location, or any combination of these and other factors. The U.S. EPA Landfill Methane Outreach Program (LMOP) estimates that, in addition to the roughly 380 landfills already collecting landfill gas for energy recovery, approximately 600 additional landfills are currently good candidates for landfill gas energy recovery. The majority of landfills have more than one million tons of waste in place and either are still accepting waste or have been closed for five or fewer years.[144]

A 2006 "state of garbage" survey shows that, in spite of slowly increasing recycling rates, the U.S. trend of increased MSW generation is continuing,[141] and the total amount of MSW generated over the next several years is expected to continue increasing as population grows.[135] While the number of operating landfills will probably continue to decrease and eventually level off, the amount of waste placed into landfills is not expected to decrease or even level off for many years. This indicates that landfill gas as an energy source should continue to be available for the foreseeable future. The number of individual sources (landfills) in the future is questionable but the amount of waste can be projected. Following current MSW generation and disposal trends, the amount of overall waste generating 90 percent of the landfill gas in landfills in 2020 could be approximately 8 billion tons.

Landfill size, and therefore the gas flow per source, can vary greatly, depending upon geographic location, ownership, regulations, localities served, and other factors. As mentioned previously, one million tons of waste in-place in a landfill will generate approximately 300 scfm of landfill gas. Around 70 percent of the landfills considered by LMOP to be current candidates for energy recovery have a waste in-place between one and five million tons with a median size of about two

[141] BioCycle, *The State of Garbage in America (Abstract only)*, April 2006.
[142] US EPA, Office of Solid Waste, Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2003, April 2005, http://www.epa.gov/epaoswer/non-hw/muncpl/pubs/msw05rpt.pdf
[143] *14th Annual Nationwide Survey of Solid Waste Management in the United States, The State of Garbage in America*, Earth Engineering Center of Columbia University and BioCycle, January 2004, http://www.earthcycle.com/ec-pdf/State percent20of percent20Garbage percent202004.pdf
[144] US EPA, Landfill Methane Outreach Program (LMOP), Landfill and Landfill Gas Energy Project database, 2006, http://www.epa.gov/lmop/proj/index.htm

million tons. [144] Therefore, an average flow per source could be represented as 600 scfm, or enough landfill gas to generate about 1.6 MW of electricity.

Gas Generation Potential

The amount of raw landfill gas that was generated in the U.S. in 2004 was approximately 3,400 million standard cubic feet per day (mmscfd) or 1,240 Bcf per year. Of this amount, about 290 Bcf per year of raw gas (150 Bcf per year of methane, assuming 50 percent methane) was utilized in landfill gas energy recovery projects while another 250 Bcf per year of raw gas was collected and flared (combustion without energy recovery). [135] The roughly 600 or so landfills identified by LMOP as being good candidates for energy recovery have a combined energy potential of approximately 264 Bcf per year. [145]

Based on the above estimate of 8 billion tons contributing to 90 percent of the landfill gas generated in 2020, the total amount of raw landfill gas generated in 2020 could be approximately 4,500 MMcfd (1,640 Bcf per year). The 1,640 Bcf per year of raw gas equates to 800 Bcf per year of methane. This can be compared to current U.S. natural gas production of roughly 20,000 Bcf per year.

Experience with Landfill Gas

LMOP reports that approximately 400 landfill gas energy projects are currently operational in the U.S. with several more under construction for completion in 2006 and additional projects planned for 2007 and beyond. [144] Several proven technologies are in use, such as reciprocating engines, gas turbines, boilers, microturbines, leachate evaporators, and individualized direct thermal applications such as brick kilns and sludge dryers. There are many other uses for landfill gas as well, and new ventures continue to emerge.

A landfill in California has been creating compressed natural gas from landfill gas for years to fuel trucks and other equipment. Several existing and planned projects involve the upgrading of landfill gas to high Btu quality and injecting it into natural gas pipelines. Combined heat and power projects are increasing in popularity as the process of recovering and using waste heat from the combustion of the landfill gas increases the overall project efficiency.

Other current and future uses for landfill gas are electricity generation from organic rankine cycle engines and Stirling ‘external combustion’ engines, heating greenhouses, fueling craft studios, and space heating with infrared heaters.

Approximately two-thirds of existing landfill gas energy projects utilize the gas to generate electricity, whether for on-site use, sale to the grid, or both. The remaining third of projects use the gas for a direct application, such as to generate steam via combustion in a boiler. **Table 41** provides basic counts of currently operational electricity-generating and direct-use projects, as reported in the LMOP database of landfill gas energy projects. [144]

[145] US EPA, Landfill Methane Outreach Program (LMOP), *An Overview of Landfill Gas Energy in the United States,* 2006, http://www.epa.gov/lmop/docs/overview.pdf

Table 41 Existing Landfill Gas Energy Technology Projects with Project Counts (February 2005)

Electricity-Generating Technology	Count of Currently Operational Projects	Direct-Use Technology	Count of Currently Operational Projects
Reciprocating Engine[a,b]	204	Boiler	38
Gas Turbine[a]	30	Direct Thermal	38
Microturbine	16	Leachate Evaporation	19
Steam Turbine	16	High Btu	9
Cogeneration[c]	13	Greenhouse	4
Combined Cycle[d]	5	Medium Btu	1
Stirling Cycle Engine	1	Alternative Fuel	1
Fuel Cell	1		
Organic Rankine Cycle[b]	2		
Total	286	Total	110

a. One project involves reciprocating engines at one landfill and a gas turbine at another landfill; for the individual counts by technology, the project is counted twice, but is only counted once for the total.

b. One project involves a reciprocating engine and an organic rankine cycle; for the individual counts by technology, the project is counted twice, but is only counted once for the total.

c. Technologies used for cogeneration include reciprocating engines, gas turbines, microturbines, and boiler/steam turbines.

d. Combined-cycle involves the use of a gas turbine and a steam turbine.

Landfill Gas Collection and Preparation

Typical gas collection begins after a portion of a landfill (called a cell) is closed. There are two collection system configurations: vertical wells and horizontal trenches. Vertical wells are by far the most common type of well used for gas collection. Trenches may be appropriate for deeper landfills, and may be used in areas of active filling. In a conventional vertical well system, vertical wells of approximately two to three feet in diameter are drilled into the waste at a typical spacing of one well per acre. Perforated polyvinyl chloride (PVC) pipe approximately six inches in diameter is inserted into the well and the hole is filled with gravel and capped with an impervious material. Each wellhead is connected to lateral piping, which transports the gas to a main collection header. Each wellhead is fitted with valves and a pressure tap so that the operator can monitor and adjust the gas flow from each well, as necessary.

An important part of any gas collection system is the condensate collection and treatment system. Condensate forms when warm, humid gas from the landfill cools as it travels through the collection system. If condensate is not removed, it can block the collection system and disrupt the energy recovery process. Typically, condensate control begins in the field collection system, where sloping pipes and headers are used to allow drainage into collecting ("knockout") tanks or traps. These systems are augmented by post-collection condensate removal as well. Some of the methods for disposal of condensate are discharge to the public sewer system, on-site treatment, and recirculation to the landfill. The best method for a particular landfill will depend upon the characteristics of the condensate (which may vary depending on site-specific waste constituents), regulatory considerations, and the cost of treatment and disposal.

A blower is necessary to pull the gas from the collection wells into the collection header, and convey the gas to the treatment system. The size, type, and number of blowers needed depend on the gas flow rate and the resistance in the collection system.

A flare is simply a device for igniting and burning the landfill gas. Flares are considered a component of each energy recovery option to dispose of gas during system start-up and downtime. In addition, it may be the most cost-effective to increase the size of the energy recovery system gradually and to flare excess gas between system upgrades (e.g., before adding another engine). Flare designs include open (or candlestick) flares and enclosed flares. Enclosed flares are more expensive but may be preferable (or required) because they allow for stack testing and can achieve slightly higher combustion efficiencies. In addition, enclosed flares may reduce noise and light nuisances.

After landfill gas has been collected, and before it is used in an energy project, it is treated to remove moisture that is not captured in the knockout tanks, as well as particulates and other impurities. Treatment requirements depend on the end use application. Minimal treatment is required for direct use of gas in boilers and reciprocating engines. This treatment includes dehumidification to drop the gas dew-point below winter temperatures, particle filters to remove particulates that could damage engine components, and compression to meet the fuel pressure requirements of the energy application. Some reciprocating engine applications and many gas turbine applications will also require siloxane removal if the level of siloxanes is very significant. [146] Siloxane removal is accomplished by adsorption beds situated after the dehumidification process.

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[146] Siloxanes are a class of compounds present in a number of consumer products. Siloxanes form hard ceramic-like deposits on combustion. These deposits can shorten the life of engines or gas turbines and also require more frequent oil changes.

Total collection system costs will vary widely, based on a number of site-specific factors. If the landfill is deep, collection costs will tend to be higher due to the fact that well depths will need to be increased. Collection costs also increase with the number of wells installed. **Table 42** presents estimated capital, and operating and maintenance costs for typical collection and treatment systems at typical landfills generating 500, 1,000, and 2,000 cubic feet per minute (cfm) of landfill gas. The capital costs for these systems include installation of all of the equipment described above and start-up costs. The annual operating and maintenance costs include all labor, materials, electricity and administrative costs required to operate the equipment described above. This includes the monthly optimization of gas collection at each wellhead. These costs translate into roughly $2.75 to $3.00 per MMBtu for low-Btu gas.

Table 42 Summary of Representative Landfill Collection and Treatment Costs (Low-Btu Gas)

(2006$)

Estimated Gas Flow (cfm)	*Capital Costs ($ million)*	**Annual O&M Costs ($ million)**
500	1.2	0.23
1,000	2.1	0.45
2,000	4.1	0.90

Source: Based on EPA's LFGcost Model

8.7 Biologic Methane

This section discusses three types of biologic methane:

- Agricultural Biogas
- Biogas from Digesters
- Wastewater Treatment Biogas

Agricultural Biogas

Agricultural biogas is the production of methane through the anaerobic digestion of agricultural byproducts. One of the most promising sources is the production of biogas from manure management at Concentrated Animal Feeding Operations (CAFOs) including dairy, swine and chicken-raising operations. The EPA estimates that there is the potential to produce 100 Bcf of biogas from swine and dairy farms alone. There is growing interest in biogas for several reasons.

First, farm operators already need to dispose of manure and anaerobic digestion is one method addressing disposal. Second, combustion of biogas is a way of reducing emissions of methane, a potent greenhouse gas. Third, biogas is classified as a renewable fuel, so its use does not count towards greenhouse gas emissions. In the past, the focus has been on using biogas for on-site power generation. More recently, developers are starting to remove impurities (CO_2 and H_2S) from the gas and supply it to end- use customers via gas pipelines. There is the potential for this pipeline use of biogas to increase significantly in the near future. Already, dairies in California and other western states are supplying biogas to pipelines.

Manure digester biogas is produced at animal production operations when manure decomposes anaerobically (without oxygen) in a digester. Animal production operations use anaerobic digestion to reduce the solids content of manure and to improve its quality. Energy-recovery digesters are specially-designed digesters that optimize the production of biogas from the decomposition of manure.

Anaerobic digesters may be designed simply to reduce and stabilize manure solids, or they may be designed to recover biogas and use it for energy. In the U.S., digesters are most commonly found at large swine and dairy operations. These animal production operations have the greatest potential for generating biogas when manure is collected and stored as a liquid, slurry, or semi-solid. Because the vast majority of large dairy and swine operations use liquid or slurry manure management systems, the biogas production potential is very significant at these operations. As biogas system size increases, the unit costs for construction and operation decrease significantly. EPA has suggested that animal operations most likely to profit from anaerobic manure digestion are dairy operations with a milking herd of more than 500 cows and swine operations with more than 2,000 head of confinement capacity. [147]

Types of sources

There are three types of energy-recovery digesters that are typically used by animal production operations in the U.S.:

- Covered anaerobic lagoon: A flexible cover is installed over a manure storage lagoon to recover biogas. This system is the simplest and most common manure storage and stabilization system currently in use. Manure waste streams with low solids content (e.g., flushed barns) are most appropriate for a covered lagoon digester system (zero to three percent solids content).

- Complete mix digester: A complete mix digester is an enclosed, heated manure storage tank that has controlled temperature, constant volume, and mixing. These digesters can accommodate total solids content in the waste stream ranging between three and 10 percent, such as a waste scraped from a swine barn or a low-water use dairy operation.

- Plug-flow digester: A plug-flow digester is a narrow, heated manure storage tank that is covered with a rigid or flexible cover. The plug-flow system operates best with scrape-collected, fresh dairy manure (>10 percent total solids).

[147] US EPA. Market Opportunities for Biogas Recovery Systems, A Guide to Identifying Candidates for On-Farm and Centralized Systems. EPA-430-8-06-004. Availabe online at: http://www.epa.gov/agstar/pdf/biogas percent20recovery percent20systems_screenres.pdf

Characteristics of Biogas

Manure digester biogas may be produced by digesters operating in one of three temperature regimes:

- Psychrophilic, or low-temperature digestion, is the natural decomposition path for manures at temperatures found in lagoons. These temperatures vary from about 38 to 85°F (3 to 29°C). Biogas production will vary seasonally with variations in lagoon temperature. Typically, uncovered lagoons operate in the psychophillic range.

- Mesophilic digestion cultivates bacteria that have peak activity between 90 and 105°F (32 to 40°C). These digesters are heated and biogas production will not vary seasonally. Most U.S. energy-recovery digesters operate in the mesophilic range.

- Thermophilic digesters promote bacteria that grow at temperatures between 135 and 155°F (57 to 68°C). These digesters are heated and biogas production will not vary seasonally. This type of digestion is unusual due to the high cost to maintain temperatures in this range.

Biogas from a manure digester typically contains, on average, 60 to 80 percent methane, depending on the type of animal and the manure collection system. The balance of the biogas is composed of carbon dioxide and trace amounts of hydrogen sulfide.

The amount of methane generated by animal type and digestion method have been estimated based on data collected from digester systems participating in EPA's AgSTAR program. As shown in **Table 43,** the actual methane generation rate will vary significantly from site to site, due to variables such as digester design, animal diet and weight, and local climatic conditions.

Table 43 Anaerobic Digestion Methane Generation by Animal Type

Animal Group	*Animal Type*	Methane Generation (cubic feet/head-day)
Dairy	Dairy Calf	38.50
Dairy	Dairy Cow: Dry	38.50
Dairy	Dairy Cow: Lactating	38.50
Dairy	Dairy Heifer	38.50
Swine	Boars	0.00
Swine	Feeder Pigs	4.40
Swine	Nursing Pigs	1.30
Swine	Sow: Gestating	6.10
Swine	Sow: Lactating	6.10
Swine	Weaned Pigs	1.30

Availability

The use of manure biogas to produce energy is limited to farms that have the animals and manure management to accommodate anaerobic digestion. Farms that produce electricity from biogas may sell the electricity back to the grid, making this energy available to consumers outside of the farm. Selling electricity back to the grid, however, has not been an economically viable option for these farms. Furthermore, not all anaerobic digesters recover energy. The number of animal operations with anaerobic digesters represents a small fraction of the total number of animal operations. Based on 2002 United States Department of Agriculture (USDA) Census of Agriculture data, there are a total of 91,989 dairy operations and 78,895 swine operations in the U.S. (**Table 44**). Out of these operations, only 0.07 percent of dairy operations and 0.05 percent of swine operations have anaerobic digesters.

In the coming years, more animal operations may consider anaerobic digestion as a manure management option. The number of operations that may be candidates for anaerobic digesters depends on the number of animals and the manure management system at each farm. Animal population and manure management system data were compiled as part of the Manure Management portion of the EPA *Inventory of United States Greenhouse Gas Emissions and Sinks: 1990 – 2004.* [148] These data can be combined with data from the Winter 2006 AgSTAR digest and the 2002 USDA Census of Agriculture to characterize the size and manure management system of animal operations in the United States.

[148] US EPA. April 2006. Inventory of United States Greenhouse Gas Emissions and Sinks: 1990 – 2004. EPA 430-R-06-002. Available online at: http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2006.html

Table 44 Number of Operations by Animal, Farm Size, and Manure Management

Animal	Farm Size (head)	Number of Operations by Manure Management System						
		Pasture, Range, or Paddock	Anaerobic Digestion	Lagoon	Liquid/ Slurry	Solid Storage	Deep Pit	Total
Dairy	≥ 500	320	48	1,614	675	245	-	2,902
	200-499	3,213	9	617	653	54	-	4,546
	1-199	68,954	5	2,223	3,017	9,195	1,147	84,541
Swine	≥ 2000	-	14	2,581	1,084	297	2,774	6,749
	200-2000	-	3	3,990	5,219	832	8,869	18,913
	1-199	53,230	1	-	-	-	-	53,231

EPA has identified dairy operations with greater than 500 head and swine operations with more than 2,000 head as the most viable candidates for anaerobic digestion. Also, the potential for generating biogas from manure is greatest for manure management systems that collect and store manure as a liquid, slurry, or semi-solid (lagoon, liquid/slurry, or deep pit). Considering these parameters, there are 2,289 dairy operations and 6,439 swine operations that are potential candidates for anaerobic digestion.

Digester Biogas

Anaerobic digestion is a biochemical process in which bacteria digest biomass in an oxygen-free environment. Several different types of bacteria work together in a digester to break down complex organic wastes; the resulting product is "biogas." Controlled anaerobic digestion requires an airtight chamber and a warm environment. To promote bacterial activity, the digester must maintain a temperature of at least 68° F, however by using higher temperatures of up to 150° F, the processing time is shortened, which allows the digester to handle a larger volume of organic waste.

Characterization

Biogas, also known as "digester gas", is actually a mixture of gases including methane and carbon dioxide (CO_2), which make up more than 90 percent of the total volume. Smaller amounts of other elements, including hydrogen sulfide, nitrogen, hydrogen, methylmercaptans and oxygen are also present. The energy content of digester gas depends on the amount of methane it contains, since methane is a combustible hydrocarbon. Methane content in digester gas varies from about 55 percent to 80 percent. Typical digester gas, with a methane concentration of 65 percent, contains about 600 Btu of energy per cubic foot.

Manure diverted to an anaerobic digester is generally collected from the animal housing area at a farm. The manure is collected frequently, as often as a few times per day or at least a few times per week in order to maintain the consistency of the manure. Manure may be scraped from the barn or flushed using recycled water. Bedding and debris are not desirable in the digester, and therefore the manure waste stream may be diverted to screens or other separation devices prior to entering the digester.

Anaerobic digester physical descriptions vary by digester type. The USDA Natural Resource Conservation Service (NRCS) has published design guidelines for each of the following three types of anaerobic digesters: [149]

- Covered Anaerobic Lagoons are defined by USDA NRCS as "a constant volume lagoon designed for methane production and recovery in conjunction with a separate waste storage facility." A cover can be floated on or suspended over the surface of a properly sized anaerobic lagoon to recover methane. Ideally, the cover is floated on the primary lagoon of a two-cell lagoon system, with the primary lagoon maintained as a constant volume treatment lagoon and the second cell used to provide storage of treated effluent until the effluent can be properly applied to land. The lagoons are not usually heated and the lagoon temperature and biogas production vary with ambient temperatures. Coarse solids, such as hay and silage fibers in cow manure, must be separated in a pretreatment step and kept from the lagoon. If dairy solids are not separated, they will float to the top and form a crust. That crust will thicken, reducing biogas production and eventually filling the lagoon.

- Complete-mix Digesters are constant volume, flow through, controlled temperature tanks designed for methane production and recovery. These digesters can accommodate the widest variety of wastes. Complete-mix digesters are usually aboveground, heated, insulated, round tanks; however, the complete-mix design has also been adapted to function in a heated, mixed, covered earthen basin. Mixing can be accomplished with gas recirculation, mechanical propellers, or liquid circulation. A complete-mix digester can be designed to maximize biogas production as an energy source or to optimize VS reduction with less regard for surplus energy.

- Plug-flow Digesters are heated, unmixed, rectangular tanks. New waste is pumped into one end of the digester, thereby displacing an equal portion of older material horizontally through the digester and pushing the oldest material out through the opposite end. Biogas formed in a digester bubbles to the surface and may be collected by a fixed rigid top, a flexible inflatable top, or a floating cover, depending on the type of digester.

The biogas produced by the manure digester is collected from the gas space between the manure and the digester cover using a low pressure blower. The biogas goes through a free water knockout vessel before being conveyed to the combustion device. Further, gas clean-up is not performed for manure operations due to the high cost of clean-up relative to the size of a typical manure operation. However, very large operations may choose to perform some of the same gas clean-up operations that were discussed for landfill gas energy systems.

[149] USDA-NRCS. Biogas Interim Digester Standards, http://www.epa.gov/agstar/resources/standards.html

Collection and Treatment System Costs

The capital, operating, and maintenance costs for each type of digester can be estimated based on cost curves developed by EPA for the AgSTAR FarmWare model. EPA developed the cost curves based on actual cost data collected from systems operating digesters who reported these financial data to EPA. The estimated costs are presented in **Table 45**.

The most economic digesters are those at dairy farms which have resource costs of $10 to $26 per MMBtu, accounting for gas used to heat the digester. In warmer climates where little or no heating of the digesters is needed, resource costs are $6.50 to $19.00 per MMBtu for dairy farm digesters.

Table 45 Estimated Cost per Head by Animal and Digester Type

Animal Type	Number of Head	Digester Type	One Time Capital Cost ($ per head)	Annual Operating and Maintenance Cost ($ per head)
Dairy	500	Covered Anaerobic Lagoon	$310	$15
Dairy	500	Complete Mix	$880	$44
Dairy	500	Plug Flow	$800	$40
Swine	2,000	Covered Anaerobic Lagoon	$80	$5
Swine	2,000	Complete Mix	$180	$9

Experience with Biogas

There are 82 anaerobic digesters recently operating at animal operations in the U.S.: 60 dairy operations, 17 swine operations, three poultry operations, one dairy/swine combined operation, and one dairy/poultry combined operation. The complete list of these anaerobic digesters is available in EPA's Winter 2006 AgSTAR Digest. **Table 46** presents a summary of the types of digesters and the operating temperature regimes of the digesters as presented in the summary.

Table 46 Anaerobic Digesters Currently Operating in the United States

Animal Type	Total Number of Operations	Digester Type: Covered Anaerobic Lagoon	Digester Type: Complete Mix	Digester Type: Plug Flow	Digester Type: Unavailable	Temperature Regime: Psychrophilic	Temperature Regime: Mesophilic	Temperature Regime: Thermophilic	Temperature Regime: Unavailable
Dairy	**60**	10	13	36	1	8	37	3	12
Swine	**17**	10	5	-	2	5	10	-	2
Poultry	**3**	-	1	2	-	-	3	-	-
Dairy/Swine	**1**	-	-	1	-	-	-	-	1
Dairy/Poultry	**1**	-	-	1	-	-	1	-	-
TOTAL	**82**	**20**	**19**	**40**	**3**	**13**	**51**	**3**	**15**

The total reported operational energy output of the currently operating digester systems is approximately 16.5 megawatts[4]. At more than 70 of the operational digester systems, the captured biogas is used to generate electricity and recover waste heat primarily for water heating. Four systems flare all of the captured gas for odor control, while the gas combustion method is unknown for six systems.

Wastewater Treatment Biogas

Wastewater treatment biogas is produced from the anaerobic digestion of domestic/industrial wastewater sludge. During the wastewater treatment process, solids from primary and secondary treatment are collected and further processed, via digestion, to stabilize and reduce the volume of the sludge. The digestion is perform either aerobically (in the presence of oxygen) or anaerobically (without oxygen) to produce biogas. Anaerobic digestion and wastewater treatment takes place in a closed or covered tank to exclude air or oxygen from the waste. Biogas is also generated from other anaerobic wastewater treatment processes including anaerobic lagoons and facultative lagoons.

Wastewater treatment biogas consists of 65-70 percent methane, 30 percent carbon dioxide and other inert gases such as nitrogen. The most common temperature range for digestion is 85ºF to 95ºF. Biogas generation is not seasonal because wastewater flows are relatively constant throughout the year, yielding a steady flow of biogas from the anaerobic digesters. Per IPCC guidelines, the maximum methane production capacity of domestic wastewater is 0.6 kg of methane per kg of BOD_5 [150] BOD_5 generation rates are reported between 0.08 to 0.12 kg per capita per day.[151] [152] A correction factor of 0.8 is also used for anaerobic treatment systems.

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[150] Doorn, Michael R.J. et al., Pre-Publication Draft 2006 IPCC guidelines for National Greenhouse Gas Inventories, Chapter 6: Wastewater Treatment and Discharge. 2006.

[151] Metcalf & Eddy, Inc. Wastewater Engineering: Treatment, Disposal, and Reuse. McGraw Hill Publishing, 2003.

[152] BOD_5 refers to biochemical oxygen demand over 5 days.

Therefore, the generation rate for anaerobic wastewater treatment system is 0.0384 to 0.0576 kg of methane per capita per day. (This is 728 to 1,075 scf per year per capita). The higher heating value (HHV) of methane is 1,012 British Thermal Units per standard cubic foot (Btu/scf). [153] Therefore, biogas that contains approximately 65-70 percent methane would have an approximate heating value of 657 to 708 Btu/scf.

Most wastewater treatment plants that utilize anaerobic digestion collect and use their biogas onsite. If used onsite, the biogas created during the anaerobic digestion process is typically collected and used without pretreatment in boilers that generate steam for space and digester heating and in reciprocating engines that drive air compressors and/or electric generators. Any excess biogas that cannot be used onsite is generally flared. The cost of the collection system piping and the blower for moving the gas through this piping is relatively insignificant in comparison to the cost of the gas utilization systems discussed in subsequent sections.

Availability

According to the 2004 CWNS, there are approximately 16,614 publicly owned treatment plants (2,658 publicly operated treatment works [POTWs] that receive domestic and industrial wastewater and 13,956 POTWs that receive domestic wastewater only). 77 percent of the POTWs receiving domestic and industrial wastewater have a flow below five million gallons per day (MGD). 87 percent of the POTWs receiving domestic wastewater only have a flow below one MGD.

Approximately 3,300 POTWs utilize anaerobic digestion, 220 utilize facultative lagoons, and seven utilize anaerobic lagoons. [154] A majority of these anaerobic systems utilize their biogas for one of three purposes: in boilers that generate steam for space and digester heating, or in reciprocating engines to drive air compressors and electric generators.

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[153] Chemical Engineers' Handbook. John H. Perry, ed. McGraw Hill Book Company, New York, 1963, Page 9-9.

[154] U.S Environmental Protection Agency, Clean Watersheds Needs Survey 2004 – Report to Congress, Office of Wastewater Management, Washington, DC. 2004.

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9 CLOSING DISCUSSION

This report evaluates the potential for unconventional natural gas to contribute to future natural gas production in North America. We have discussed the status of U.S. and Canadian activity and production and the role that is now being played by tight gas, coalbed methane and shale gas. Industry has made a major shift toward unconventional gas development, and the current emphasis is on developing tight gas and shale gas resources. Coalbed methane activity also contributes significantly to production.

The rapid expansion of horizontal shale gas development in the U.S. has ushered in a new era for North American gas supply. The emergence of several new plays spread across numerous basins in the U.S. and Canada has major implications for future production, both nationally and regionally. It is now apparent that we will see activity and increased shale gas production in many areas of the U.S. and Canada in coming decades.

Tight gas development has surged in Wyoming, Colorado, Utah, and Texas, and activity continues to increase. The undeveloped potential in these areas is excellent.

Expansion of unconventional natural gas production has had a large impact on the natural gas transportation and processing industries. Areas of intense infrastructure activity over the past decade include Wyoming, East Texas, and the Mid-Continent. Gas production in the Rockies has increased so rapidly, that major pipeline expansions were required to move gas from the region.

Environmental and regulatory issues will likely impact the development of unconventional resources. These include well and environmental permitting and related costs, land access, water use and disposal, and surface disturbance. Water use and disposal for fracturing of shale wells has already emerged as a significant issue, although to date it has not significantly restricted development in most cases.

This report also evaluates other forms of unconventional gas, including aboveground and underground coal gasification, gas from oil shales, landfill gas, biogas, and gas hydrates. With the exception of aboveground gasification and landfill gas, most of these will not contribute significantly to North American gas production through 2020. However, the tremendous volumes of potentially available gas warrant improved understanding and expanded research.