# Chapter 2: Supply

## INTRODUCTION AND CONTEXT

In this chapter, we discuss various aspects of natural gas supply: how much natural gas exists in the world; at what rate can it be produced and what it will cost to develop. Following the introduction and definitions, we look at production history, resource volumes and supply costs for natural gas — first from a global perspective, and then focusing in more detail on the U.S., paying particular attention to the prospects for shale gas. We then discuss the science and technology of unconventional gas, the environmental impacts of shale gas development and finally the prospects for methane hydrates.

## NATURAL GAS AND THE RECOVERY PROCESS

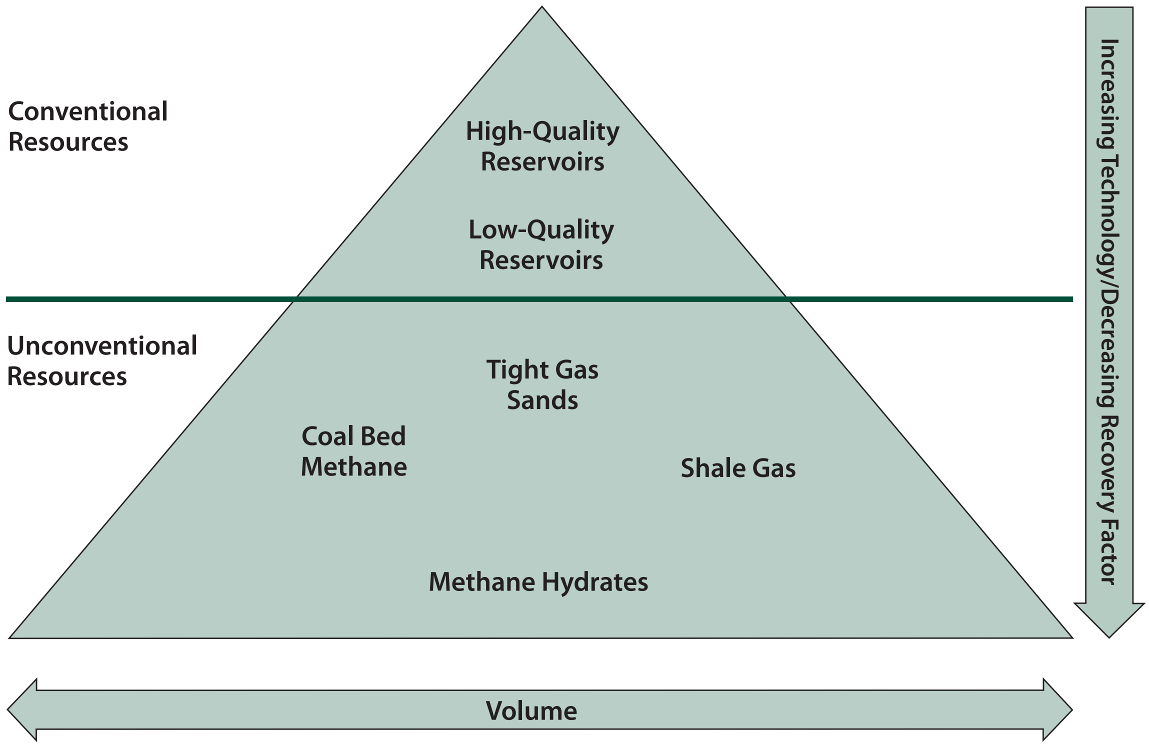
The primary chemical component of natural gas is methane, the simplest and lightest hydrocarbon molecule, comprised of four hydrogen (H) atoms bound to a single carbon (C) atom. In chemical notation, this is expressed as $CH_4$ (the symbol for methane). Natural gas may also contain small proportions of heavier hydrocarbons: ethane ($C_2H_6$); propane ($C_3H_8$) and butane ($C_4H_{10}$); these heavier components are often extracted from the producing stream and marketed separately as natural gas liquids (NGL). In the gas industry, the term "wet gas" is used to refer to natural gas in its raw unprocessed state, while "dry gas" refers to natural gas from which the heavier components have been extracted.

Thermogenic[1] natural gas, which is formed by the application, over geological time, of enormous heat and pressure to buried organic matter, exists under pressure in porous rock formations thousands of feet below the surface of the earth. It exists in two primary forms: "associated gas" is formed in conjunction with oil, and is generally released from the oil as it is recovered from the reservoir to the surface — as a general rule the gas is treated as a by-product of the oil production process; in contrast, "non-associated gas" is found in reservoirs that do not contain oil, and is developed as the primary product. While associated gas is an important source, the majority of gas production is non-associated; 89% of the gas produced in the U.S. is non-associated.

Non-associated gas is recovered from the formation by an expansion process. Wells drilled into the gas reservoir allow the highly compressed gas to expand through the wells in a controlled manner, to be captured, treated and transported at the surface. This expansion process generally leads to high recovery factors from conventional, good-quality gas reservoirs. If, for example, the average pressure in a gas reservoir is reduced from an initial 5,000 pounds per square inch (psi) to 1,000 psi over the lifetime of the field, then approximately 80% of the Gas Initially In Place (GIIP) will be recovered. This is in contrast to oil, where recovery factors of 30% to 40% are more typical.

Gas is found in a variety of subsurface locations, with a gradation of quality as illustrated in the resource triangle in Figure 2.1.

**Figure 2.1 GIIP as a Pyramid in Volume and Quality. Conventional reservoirs are at the top of the pyramid. They are of higher quality because they have high permeability and require less technology for development and production. The unconventional reservoirs lie below the conventional reservoirs in this pyramid. They are more abundant in terms of GIIP but are currently assessed as recoverable resources — and commercially developed — primarily in North America. They have lower permeability, require advanced technology for production and typically yield lower recovery factors than conventional reservoirs.**

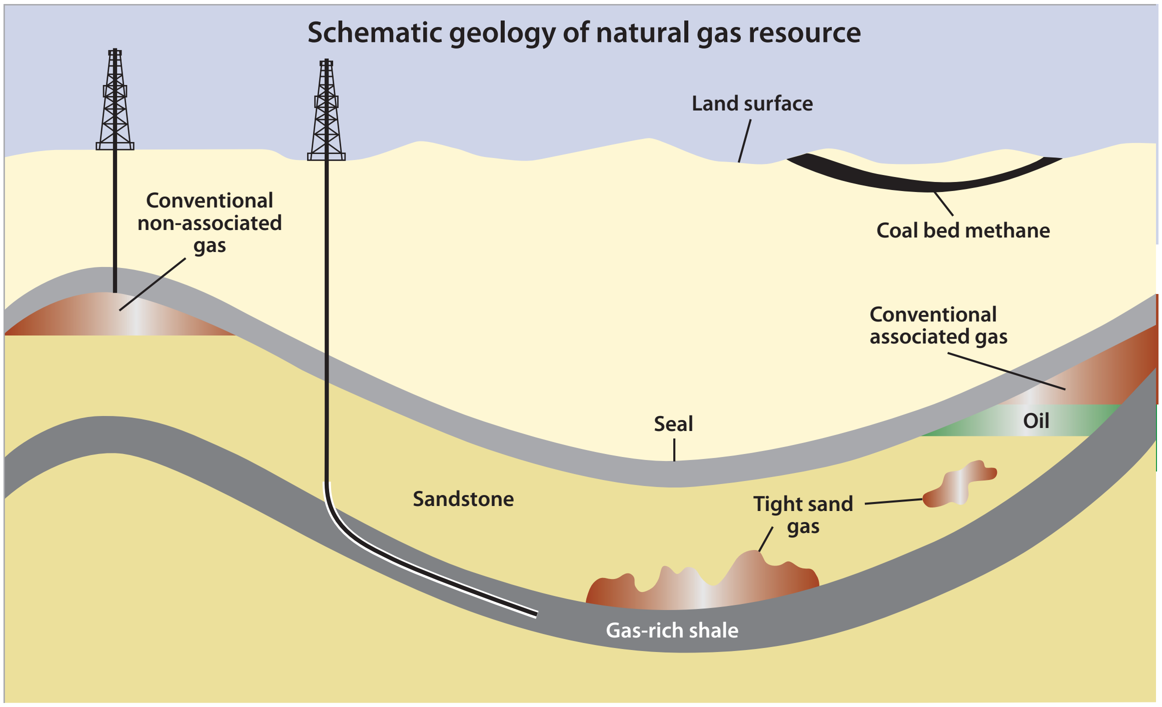



Adapted from Holditch 2006

Conventional resources exist in discrete, well-defined subsurface accumulations (reservoirs), with permeability[2] values greater than a specified lower limit. Such conventional gas resources can usually be developed using vertical wells, and generally yield the high recovery factors described above.

By contrast, unconventional resources are found in accumulations where permeability is low. Such accumulations include "tight" sandstone formations, coal beds (coal bed methane or CBM) and shale formations. Unconventional resource accumulations tend to be distributed over a larger area than conventional accumulations and usually require advanced technology such as horizontal wells or artificial stimulation in order to be economically productive; recovery factors are much lower — typically of the order of 15% to 30% of GIIP. The various resource types are shown schematically in Figure 2.2.

**Figure 2.2 Illustration of Various Types of Gas Resource**




Source: U.S. Energy Information Administration

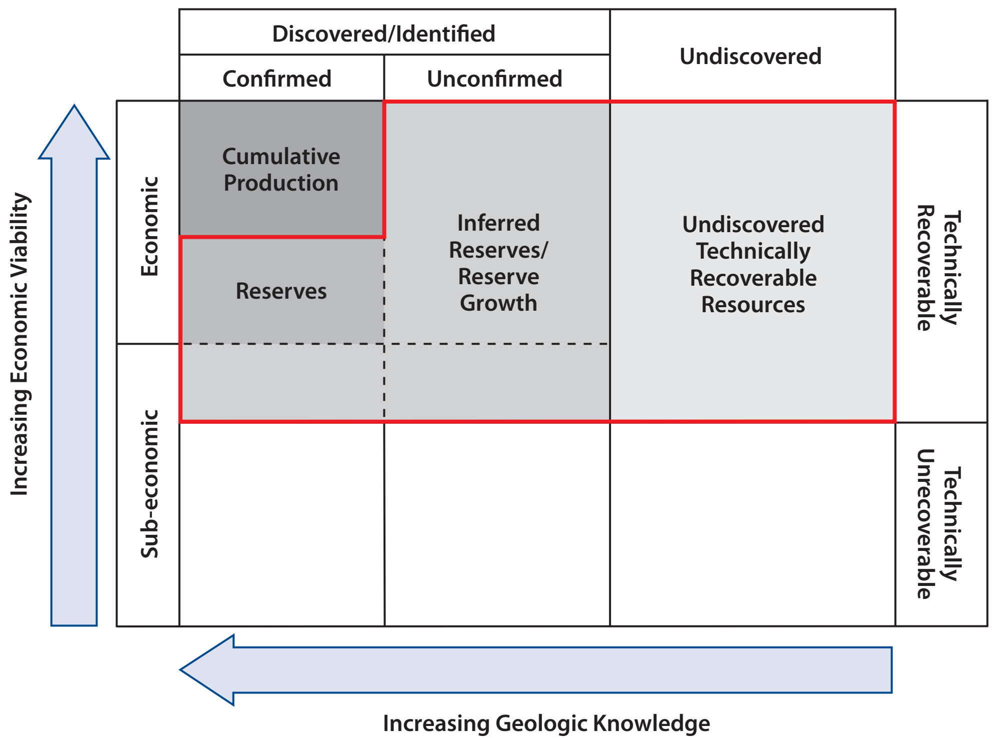
## RESOURCE DEFINITIONS

The complex cross-dependencies between geology, technology and economics mean that the use of unambiguous terminology is critical when discussing natural gas supply. In this study, the term "resource" will refer to the sum of all gas volumes expected to be recoverable in the future, given specific technological and economic conditions. The resource can be disaggregated into a number of sub-categories; specifically, "proved reserves," "reserve growth" (via further development of known fields) and "undiscovered resources," which represent gas volumes that are expected to be discovered in the future via the exploration process.

*Gas resources are an economic concept — a function of many variables, in particular the cost of exploration, production and transportation relative to the price of sale to users.*

Figure 2.3 illustrates how proved reserves, reserve growth and undiscovered resources combine to form the "technically recoverable resource," that is, the total volume of natural gas that could be recovered in the future, using today's technology, ignoring economic constraints.

**Figure 2.3 Modified McKelvey Diagram, Showing the Interdependencies between Geology, Technology and Economics and Their Impacts on Resource Classes; Remaining Technically Recoverable Resources Are Outlined in Red**




The methodology used in analyzing natural gas supply for this study places particular emphasis in two areas:

1. Treating gas resources as an economic concept — recoverable resources are a function of many variables, particularly the ultimate price that the market will pay. A set of supply curves has been developed using the ICF[3] Hydrocarbon Supply Model with volumetric and fiscal input data supplied by ICF and MIT. These curves describe the volume of gas that is economically recoverable for a given gas price. These curves form a primary input to the integrated economic modelling in Chapter 3 of this report.

2. Recognizing and embracing uncertainty — uncertainty exists around all resource estimates due to the inherent uncertainty associated with the underlying geological, technological, economic and political conditions. The analysis of natural gas supply in this study has been carried out in a manner that frames any single point resource estimate within an associated uncertainty envelope, in order to illustrate the potentially large impact this ever-present uncertainty can have.

The volumetric data used as the basis of the analysis for both the supply curve development and the volumetric uncertainty analysis was compiled from a range of sources. In particular, use has been made of data from work at the United States Geological Survey (USGS), the Potential Gas Committee (PGC), the Energy Information Agency (EIA), the National Petroleum Council (NPC) and ICF International.

## GLOBAL SUPPLY

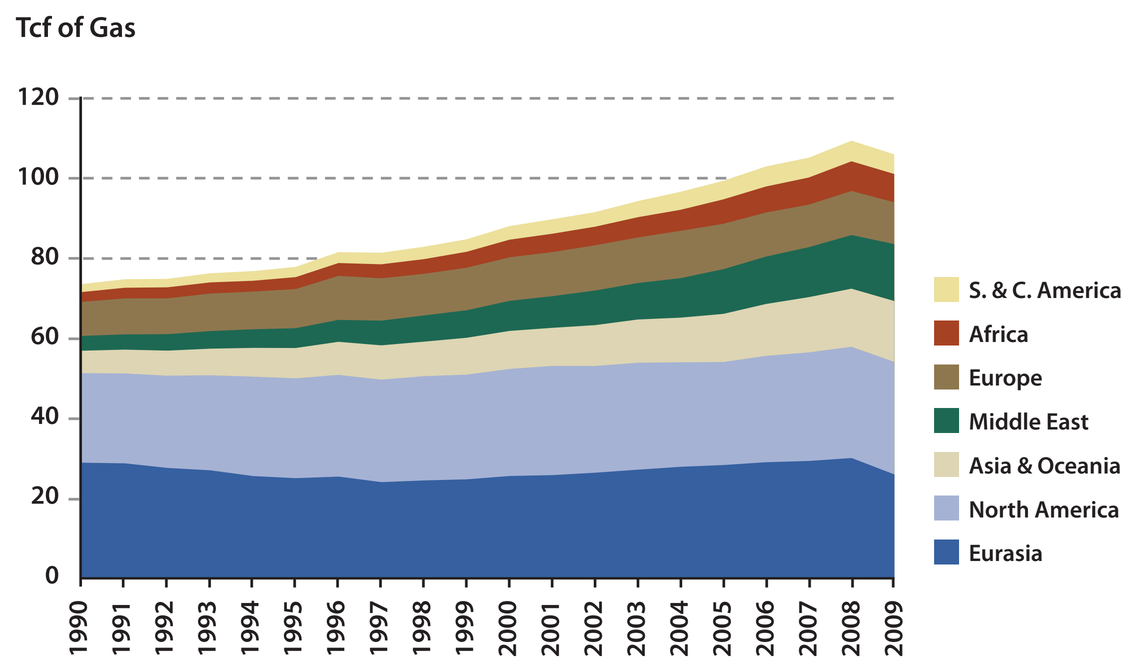
### Production Trends

Over the past two decades, global production of natural gas has grown significantly, rising by almost 42% overall from approximately 74 trillion cubic feet (Tcf)[4] in 1990 to 105 Tcf in 2009. This is almost twice the growth rate of global oil production, which increased by around 22% over the same period. Much of the gas production growth has been driven by the rapid expansion of production in areas that were not major gas producers prior to 1990. This trend is illustrated in Figure 2.4, which shows how growth in production from regions such as the Middle East, Africa and Asia & Oceania has significantly outpaced growth in the traditional large producing regions, including North America and Eurasia (primarily Russia).

Figure 2.5 compares the 1990 and 2009 annual production levels for the 10 largest gas-producing nations (as defined by 2009 output). In addition to demonstrating the overwhelming scale of the United States and Russia compared to other producing countries, this figure illustrates the very significant growth rates in other countries. The substantial growth of new gas producing countries over the period reflects the relative immaturity of the gas industry on a global basis outside Russia and North America, the expansion of gas markets and the rise in global cross-border gas trade.

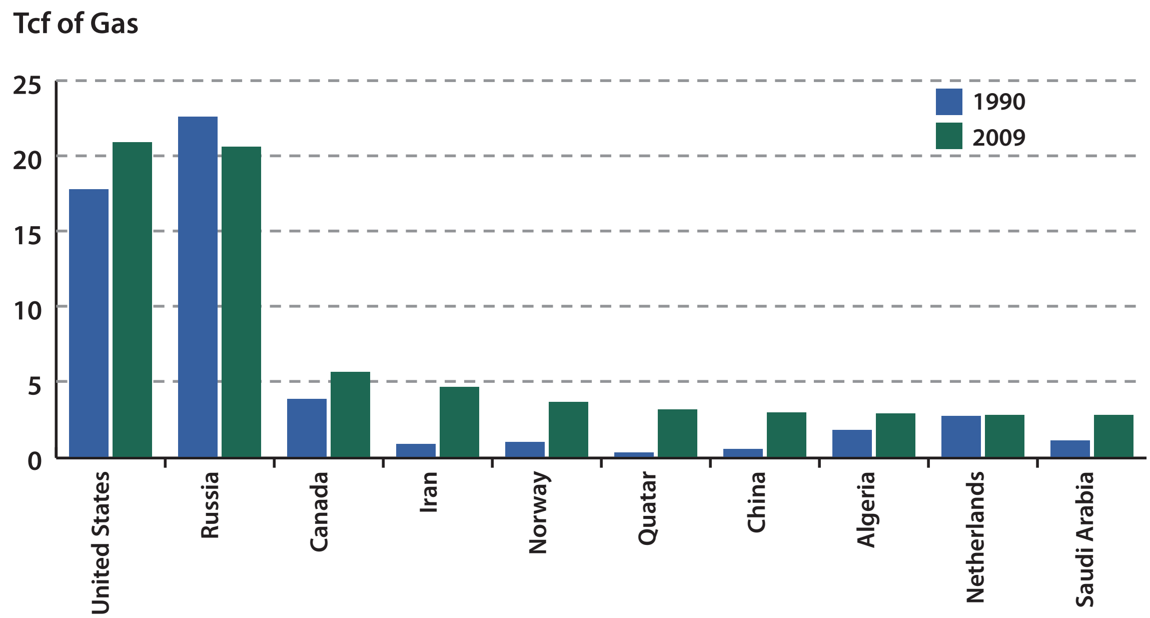
Between 1993 and 2008, global cross-border gas trade almost doubled, growing from around 18 Tcf (25% of global supply) to around 35 Tcf (32% of global supply). Most of the world's gas supply is transported from producing fields to market by pipeline. However, the increase in global gas trade has been accelerated by the growing use of Liquefied Natural Gas (LNG), which is made by cooling natural gas to around -162°C. Under these conditions, natural gas becomes liquid, with an energy density 600 times that of gas at standard temperature and pressure — and it can be readily transported over long distances in specialized ocean-going

**Figure 2.4 Trends in Annual Global Dry Gas Production by Region between 1990 and 2009**



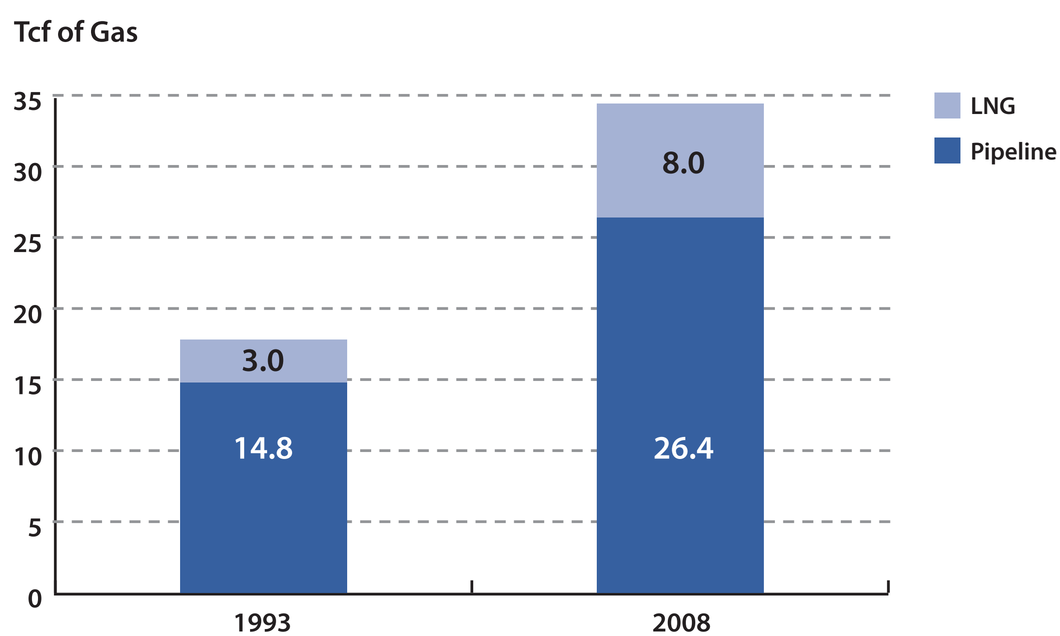

Source: MIT; U.S. Energy Information Administration

**Figure 2.5 Comparison of 1990 and 2009 Natural Gas Production Levels for the Top 10 Natural Gas Producing Nations (as defined by 2009 output)**




Source: MIT; U.S. Energy Information Administration

**Figure 2.6 Global Cross-Border Gas Trade**




Source: MIT; U.S. Energy Information Administration

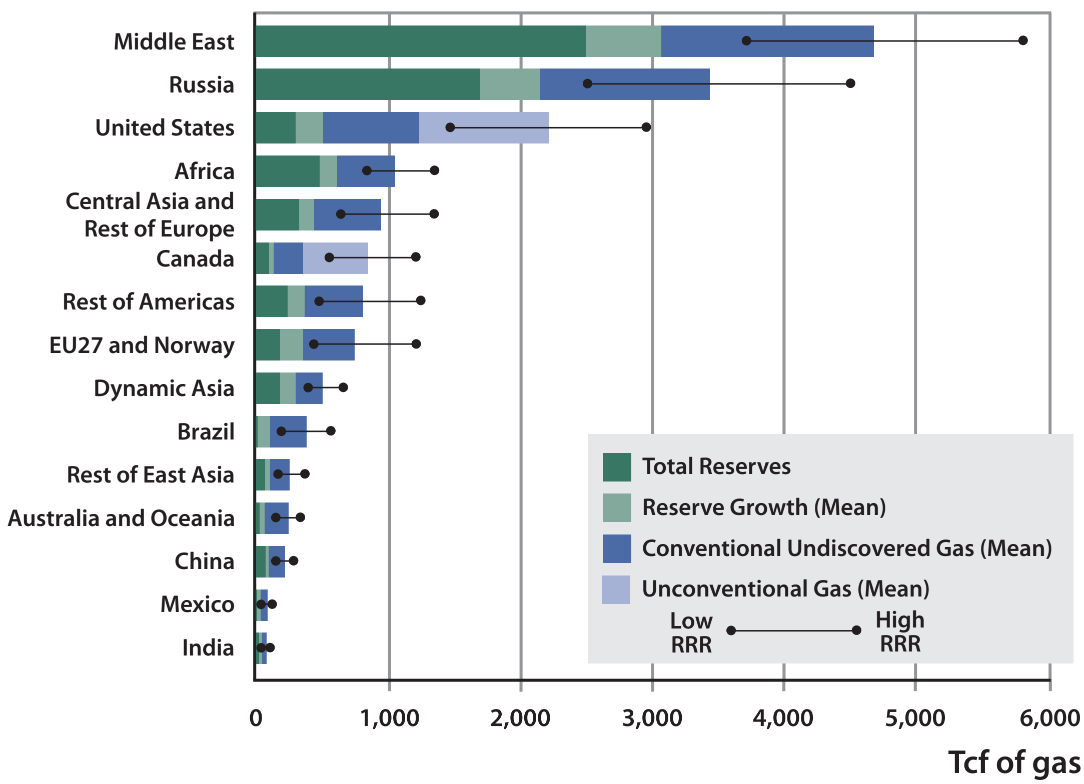
LNG tankers. Over this 15-year period, global gas trade doubled, while LNG trade increased even more rapidly, as shown in Figure 2.6.

## RESOURCES[5]

Global natural gas resources are abundant. The mean remaining resource base is estimated to be 16,200 Tcf, with a range between 12,400 Tcf (with a 90% probability of being exceeded) and 20,800 Tcf (with a 10% probability of being exceeded). The mean projection is 150 times the annual consumption in 2009. With the exception of Canada and the U.S., this estimate does not include any unconventional supplies. The global gas supply base is relatively immature; outside North America only 11% of the estimated ultimately recoverable conventional resources have been produced to date.

Figure 2.7 depicts the estimated remaining recoverable gas resources, together with estimated uncertainty,[6] broken down by regions as defined by the Emissions Prediction and Policy Analysis (EPPA) model employed in Chapter 3 of this report. Figure 2.8 depicts the geographical distribution of EPPA regions, together with the mean resource estimate for each region. The resources are comprised of three major components defined above: reserves, reserve growth and yet-to-find resources. For the U.S. and Canada, we have also included a fourth category, unconventional resources. As discussed later, due to the very high levels of uncertainty at this stage, we have not included unconventional resource estimates for other regions.

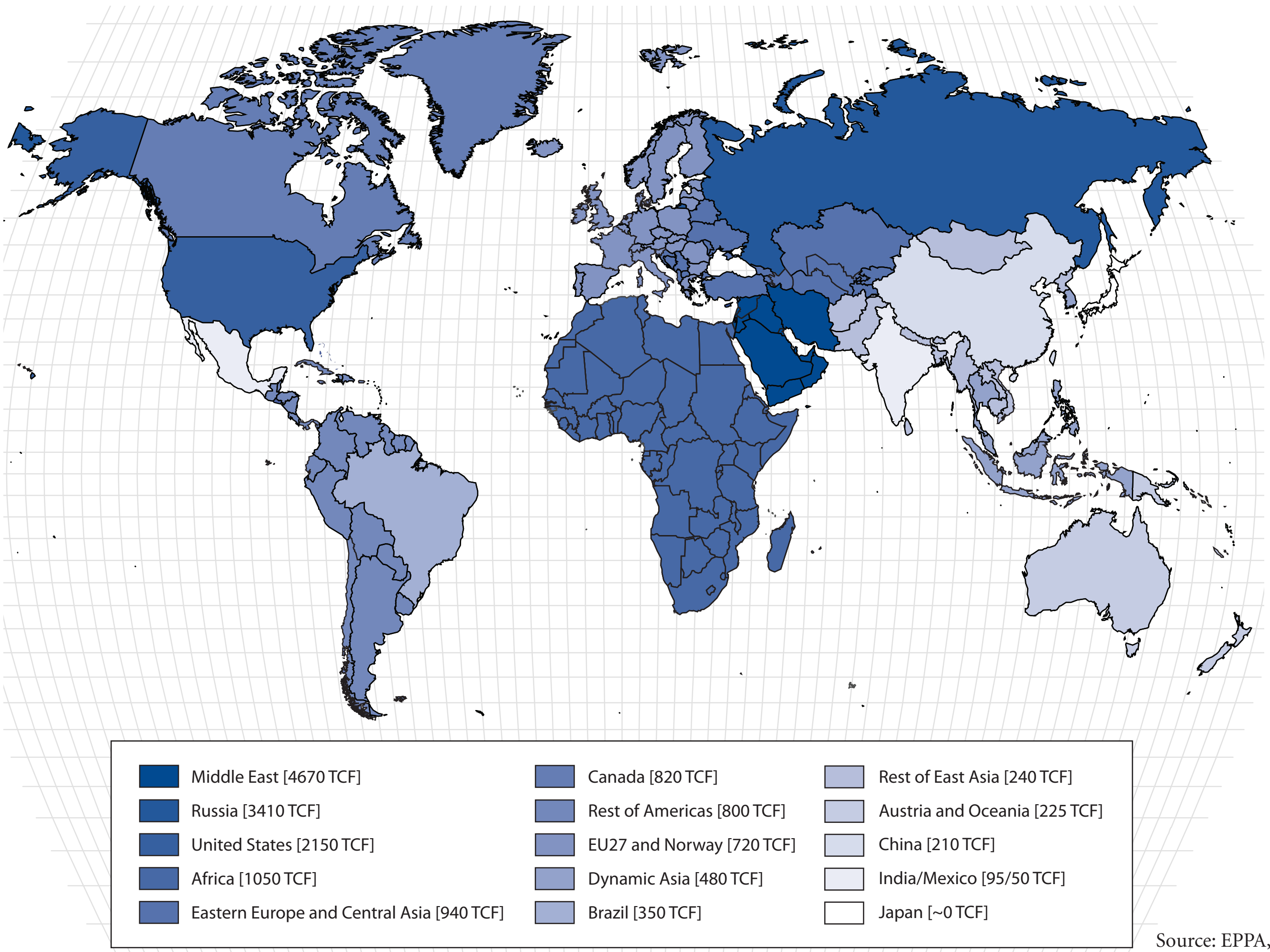
**Figure 2.7 Global Remaining Recoverable Gas Resource by EPPA Region, with Uncertainty**




Source: MIT analysis based on data and information from: Ahlbrandt et al. 2005; United States Geological Survey 2010; National Petroleum Council 2003; United States Geological Survey n.d.; Potential Gas Committee 1990; Attanasi & Coburn 2004; Energy Information Administration 2009

Although resources are large, the supply base is concentrated geographically, with an estimated 70% in only three regions: Russia, the Middle East (primarily Qatar and Iran) and North America (where North American resources also include unconventional gas). By some measures, global supplies of natural gas are even more geographically concentrated than oil supplies. Political considerations and individual country depletion policies play at least as big a role in global gas resource development as geology and economics, and dominate the evolution of the global gas market.

**Figure 2.8 Map of EPPA Regions, and Mean Resource Estimates**




Source: EPPA, MIT

## SUPPLY COSTS[7]

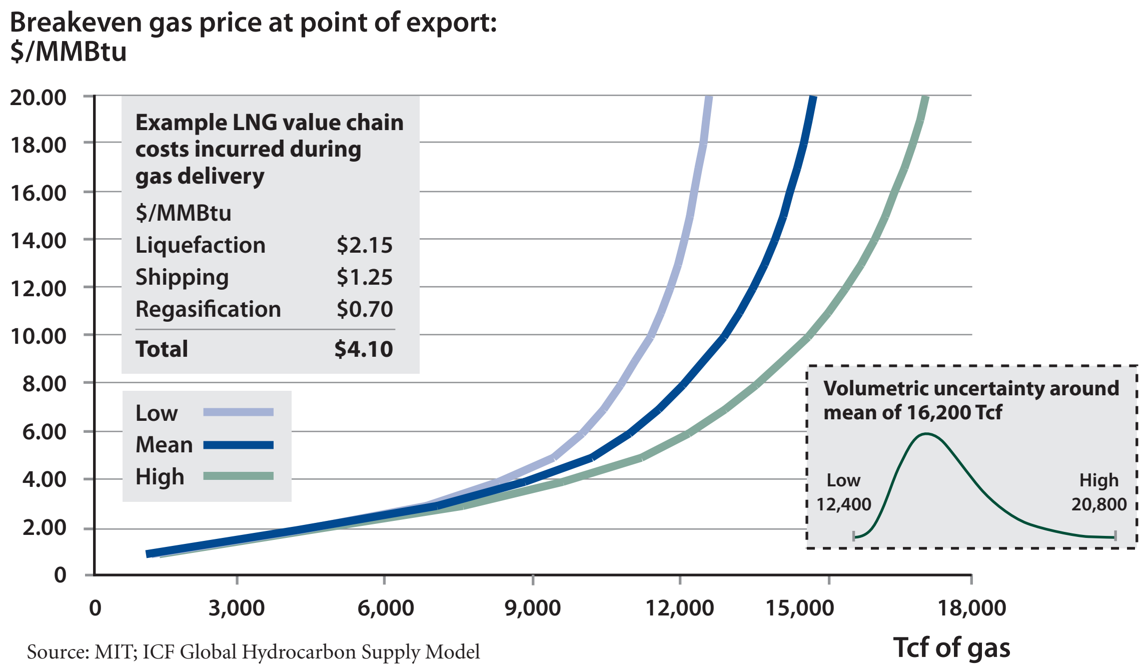
Figure 2.9 depicts a set of global supply curves, which describe the resources of gas that can be developed economically at given prices at the point of export. The higher the price, the more gas will ultimately be developed. Much of the global supply can be developed economically with relatively low prices at the wellhead or the point of export.[8] However, the cost of delivering this gas to market is generally considerably higher.

In contrast to oil, the total cost of delivering gas to international markets is strongly influenced by transportation costs, either via long-distance pipeline or as LNG. Transportation costs will obviously be a function of distance, but by way of illustration, resources that can be economically developed at a gas price of $1 or $2/million British thermal units (MMBtu) may well require an additional $3 to $5/MMBtu of transport costs to get to their ultimate destination. These high transportation costs are also a significant factor in the evolution of the global gas market.

Figure 2.10 depicts the mean gas supply curves for those EPPA regions that contain significant gas resources. Again, this illustrates the significant concentration of gas resources in the world.

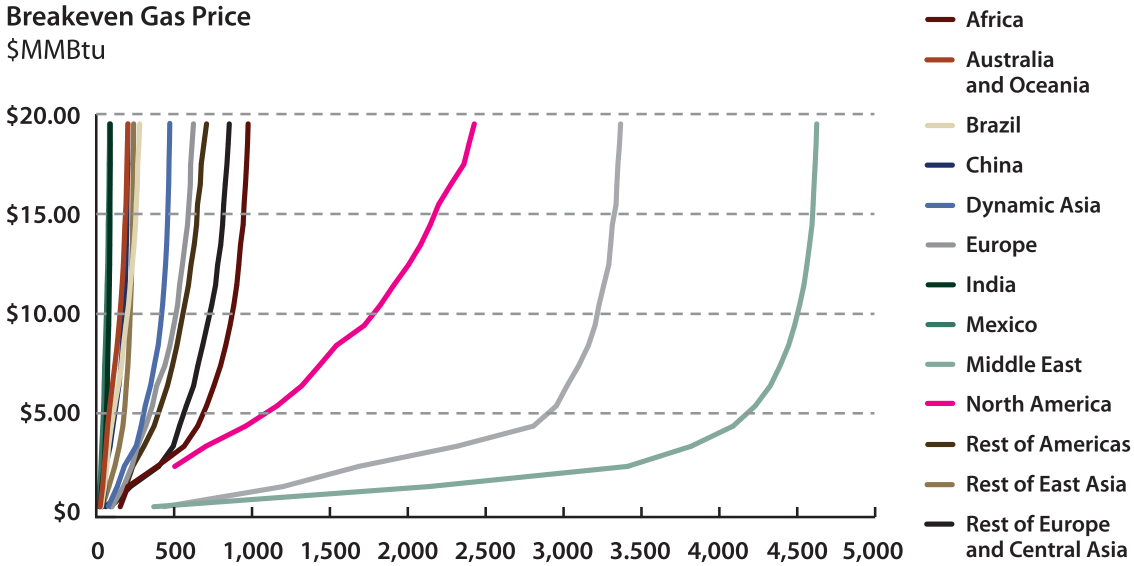
*In contrast to oil, the total cost of getting gas to international markets is strongly influenced by the cost of transportation — a significant factor in the evolution of the global gas market.*

**Figure 2.9 Global Gas Supply Cost Curve, with Uncertainty; 2007 Cost Base**




Source: MIT; ICF Global Hydrocarbon Supply Model

**Figure 2.10 Global Gas Supply Cost Curve by EPPA Region; 2007 Cost Base**




Source: MIT; ICF Global Hydrocarbon Supply Model

## UNCONVENTIONAL RESOURCES[9]

Outside of Canada and the U.S., there has been very little development of the unconventional gas supply base — indeed there has been little need when conventional resources are so abundant. But due to this lack of development, unconventional resource estimates are sparse and unreliable.

Based on an original estimate by Rogner[10], there may be of the order of 24,000 Tcf of unconventional GIIP outside North America. Applying a nominal 25% recovery factor, this would imply around 6,000 Tcf of unconventional recoverable resources. However, these global estimates are highly speculative, almost completely untested and subject to very wide bands of uncertainty. There is a long-term need for basin-by-basin resource evaluation to provide credibility to the GIIP estimates and, most importantly, to establish realistic estimates of recoverable resource volumes and costs[11].

Given the concentrated nature of conventional supplies and the high costs of long-distance transportation, there may be considerable strategic and economic value in the development of unconventional resources in those regions that are currently gas importers, such as Europe and China. It would be in the strategic interest of the U.S. to see these indigenous supplies developed. As a market leader in this technology, the U.S. could play a significant role in facilitating this development.

**RECOMMENDATION**

**U.S. policy should encourage the strategic development of unconventional gas supplies in regions which currently depend on imported gas, in particular, Europe and China.**

## UNITED STATES SUPPLY

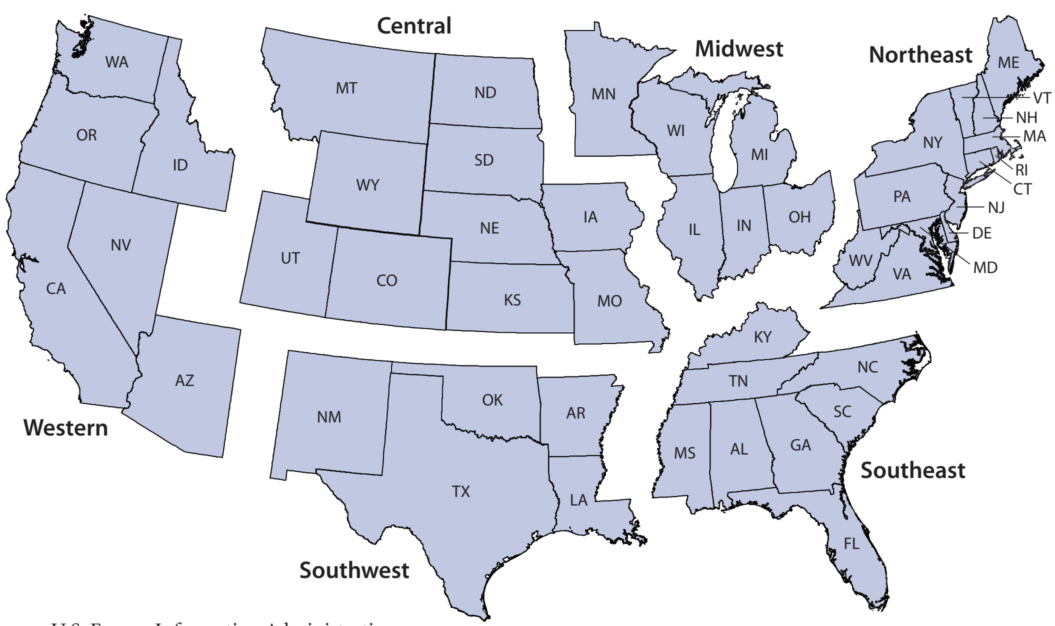
### Production Trends

There is significant geographical variation in U.S. natural gas production levels. For the purposes of this discussion of U.S. production, we will use the U.S. EIA pipeline regions (Figure 2.11).

Natural gas production in the U.S. has traditionally been associated with the Southwest region and the Gulf of Mexico. However, significant production also takes place in Alaska and in the Central region. In the case of Alaska, the vast majority of the gas is associated with oil production on the North Slope, and due to the lack of an export mechanism, this gas is re-injected to enhance recovery from Alaskan oil fields. These gas production volumes are therefore not included in the national gas production figures reported by the EIA. Small volumes of gas are exported from Alaska to Japan as LNG.

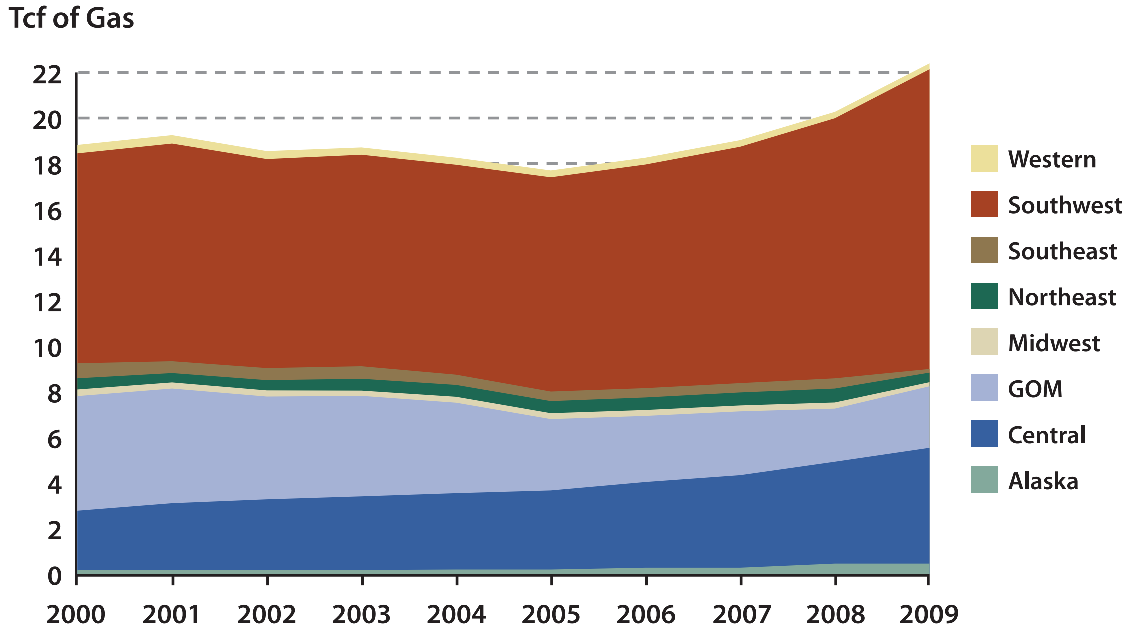
Figure 2.12 illustrates the regional breakdown of dry natural gas production in the U.S. since 2000. Some level of production occurs in all eight regions, but the dominance of the Southwest, Gulf of Mexico and Central regions is clearly shown. The dynamics of the production levels across these major regions have differed appreciably over the past decade. In the Southwest, the largest gas producing region, annual production levels remained relatively flat at about 9.3 Tcf from 2000 to 2005. Since 2005, output from the region has increased, growing by 21% to 11.4 Tcf in 2008. Much of this growth in the latter half of the decade is the result of rapid expansion in the production of gas from shale plays.

**Figure 2.11 EIA Natural Gas Pipeline Regions for the L48 States; the State of Alaska and the U.S. Offshore Territory in the Gulf of Mexico Form Two Additional Regions**




Source: U.S. Energy Information Administration

**Figure 2.12 Regional Breakdown of Annual Dry Gas Production in the U.S. between 2000 and 2009**




Source: MIT; U.S. Energy Information Administration

Since 2000, the Central region has seen the greatest percentage growth in production among U.S. regions. Annual dry gas output has risen from 2.6 Tcf to 4.5 Tcf, an overall increase of 75%. Unlike the Southwest region, production from the Central region has grown continuously since 2000, with output increasing from all resource types. In marked contrast, gas output from offshore fields in the Gulf of Mexico has fallen dramatically from approximately 5 Tcf in 2000 to 2.4 Tcf in 2008, the result of fewer new wells being brought online in the Gulf to replace those older wells that are now in decline or have been taken off production. This decline is an indication of the maturity of the conventional resource base in the Gulf of Mexico.

## PRODUCTION TRENDS BY RESOURCE TYPE IN THE UNITED STATES

In a global context, U.S. gas production by type is extremely diverse. Both conventional and unconventional gas output is significant, with the contribution of unconventional gas growing steadily year-on-year.

Figure 2.13a plots contributions to production from conventional, unconventional and associated gas. This breakdown illustrates the marked shift towards unconventional resources that has been a feature of gas production in the U.S. over the past decade and more. In 2000, the combined gross production of conventional and associated gas in the L48 states was 14.6 Tcf (71% of total output). By 2009, the combined conventional and associated output had fallen to 11.4 Tcf (52% of the total). In concert with this fall in conventional and associated gas production, there has been continuous expansion in the production of unconventional gas, with approximately 4.5 Tcf more unconventional gas being produced in 2009 than in 2000.

**Figure 2.13a Breakdown by Type of Annual Gross Gas Production in the L48 U.S. between 2000 and 2009**

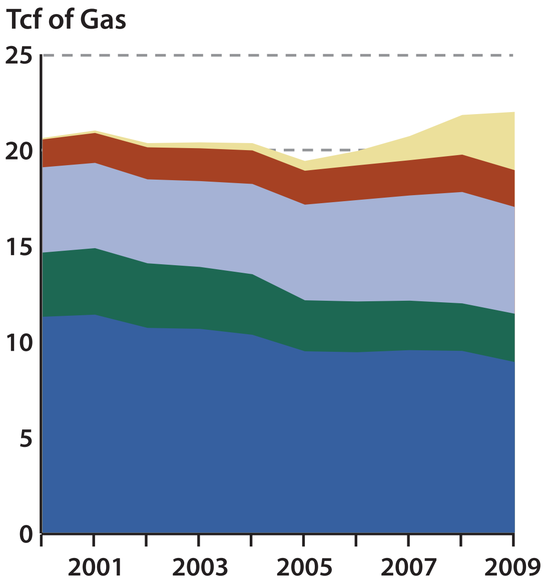
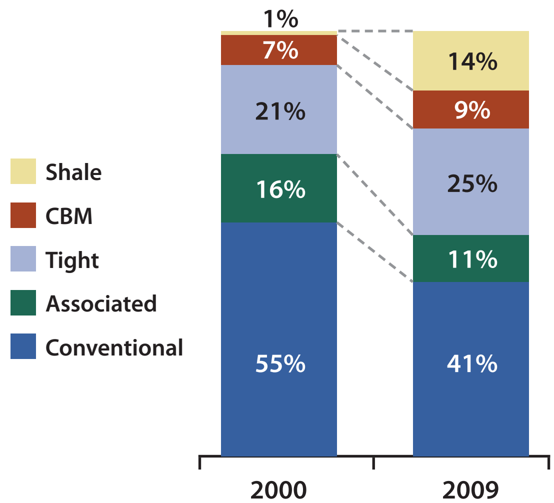



**Figure 2.13b Percentage Breakdown by Type of Gross Gas Production in the L48 U.S. in 2000 and 2009**




Source: MIT; HPDI production database

Historically, tight gas has been the most significant source of unconventional gas production in the U.S., and is likely to remain so for some time. Tracking tight gas production can be difficult because it can exist in a continuum with conventional gas. However, a review of output from known tight plays shows a growth in annual output from 4.5 Tcf to 5.6 Tcf between 2000 and 2009, an increase from 21% to 25% of total gross production as shown in Figure 2.13b. Commercial production of CBM began at the end of the 1980s, and grew substantially during the 1990s from an output of 0.2 Tcf in 1990 to 1.3 Tcf in 1999. This growth moderated during the last decade, with 2009 CBM output standing at 1.92 Tcf or 9% of the total.

Aside from the fall in conventional production, the most striking feature of the gas production in the U.S. this past decade has been the emergence of shale gas. Although shale resources have been produced in the U.S. since 1821, the volumes have not been significant. This situation changed fundamentally during the past decade as technological advances enabled production from shales previously considered uneconomical. Expansion in shale gas output is illustrated in Figures 2.13a and 2.13b. From 2000 to 2009, the contribution of shale gas to overall production grew from 0.1 Tcf, or less than 1%, to 3.0 Tcf, or nearly 14%. This growth is all the more remarkable in that 80% of it was driven by one play, the Barnett shale, located in Texas' Fort Worth Basin. Activity in other shale plays has also been increasing, with appreciable volumes now being produced from the Fayetteville and Woodford shales in the Arkoma Basin, the Haynesville shale in the East Texas Basin and as of the end of 2009, the Marcellus shale in the Appalachian Basin.

## U.S. RESOURCES[12]

Table 2.1 illustrates mean U.S. resource estimates from a variety of resource assessment authorities. These numbers have tended to grow over time, particularly as the true potential of the unconventional resource base has started to emerge over the past few years.

For this study, we have assumed a mean remaining resource base of around 2,100 Tcf. This corresponds to approximately 92 times the annual U.S. consumption of 22.8 Tcf in 2009. We estimate the low case (with a 90% probability of being met or exceeded) at 1,500 Tcf, and the high case (with a 10% probability of being met or exceeded) at 2,850 Tcf.

Around 15% of the U.S. resource is in Alaska, and full development of this resource will require major pipeline construction to bring the gas to market in the L48 states. Given the abundance of L48 supplies, development of the pipeline is likely to be deferred yet again, but this gas represents an important resource for the future.

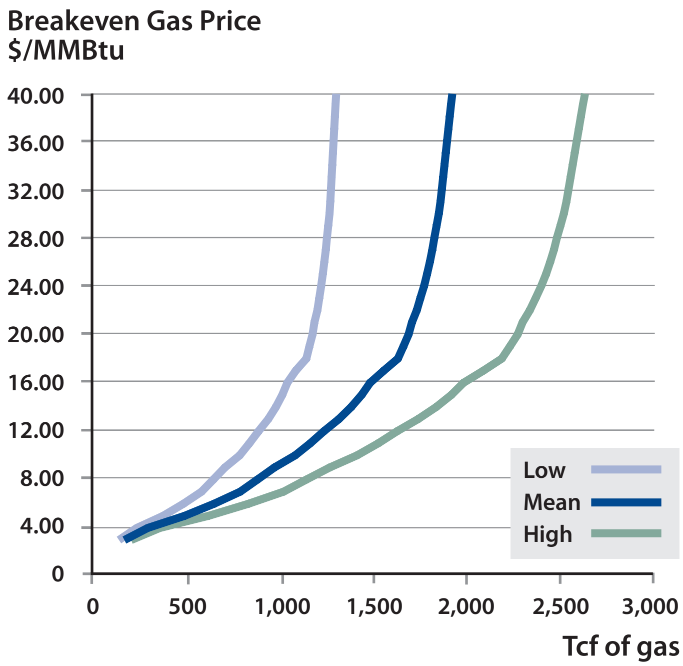
In the L48, some 55% to 60% of the resource base is conventional gas, both onshore and offshore. Although mature, the conventional resource base still has considerable potential. Around 60% of this resource is comprised of proved reserves and reserve growth, with the remainder — of the order of 450 to 500 Tcf — from expected future discoveries.

**Table 2.1 Tabulation of US Resource Estimates by Type, from Different Sources**

<table>
<tr><th></th><th>NPC</th><th>USGS/MMS</th><th colspan="2">PGC</th><th>ICF</th></tr>
<tr><td></td><td>(2003)</td><td>(Various Years)</td><td>(2006)</td><td>(2008)</td><td>(2009)</td></tr>
<tr><td>L48</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Conventional</td><td>691</td><td>928</td><td rowspan="3">966</td><td rowspan="2">869</td><td>693</td></tr>
<tr><td>Tight</td><td>175</td><td>190</td><td>174</td></tr>
<tr><td>Shale</td><td>35</td><td>85</td><td>616</td><td>631</td></tr>
<tr><td>CBM</td><td>58</td><td>71</td><td>108</td><td>99</td><td>65</td></tr>
<tr><td>Total L48</td><td>959</td><td>1,274</td><td>1,074</td><td>1,584</td><td>1,563</td></tr>
<tr><td>Alaska</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Conventional</td><td>237</td><td>357</td><td rowspan="3">194</td><td rowspan="2">194</td><td rowspan="2">237</td></tr>
<tr><td>Tight</td><td>–</td><td>–</td></tr>
<tr><td>Shale</td><td>–</td><td>–</td><td>–</td><td>–</td></tr>
<tr><td>CBM</td><td>57</td><td>18</td><td>57</td><td>57</td><td>57</td></tr>
<tr><td>Total Alaska</td><td>294</td><td>375</td><td>251</td><td>251</td><td>294</td></tr>
<tr><td>U.S.</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Conventional</td><td>929</td><td>1,284</td><td rowspan="3">1,160</td><td rowspan="2">1,063</td><td>930</td></tr>
<tr><td>Tight</td><td>175</td><td>190</td><td>174</td></tr>
<tr><td>Shale</td><td>35</td><td>85</td><td>616</td><td>631</td></tr>
<tr><td>CBM</td><td>115</td><td>89</td><td>165</td><td>156</td><td>122</td></tr>
<tr><td>Total U.S.</td><td>1,254</td><td>1,648</td><td>1,325</td><td>1,835</td><td>1,857</td></tr>
<tr><td>Proved Reserves</td><td>184</td><td>245</td><td>204</td><td>245</td><td>245</td></tr>
<tr><td>Total (Tcf)</td><td>1,438</td><td>1,893</td><td>1,529</td><td>2,080</td><td>2,102</td></tr>
</table>

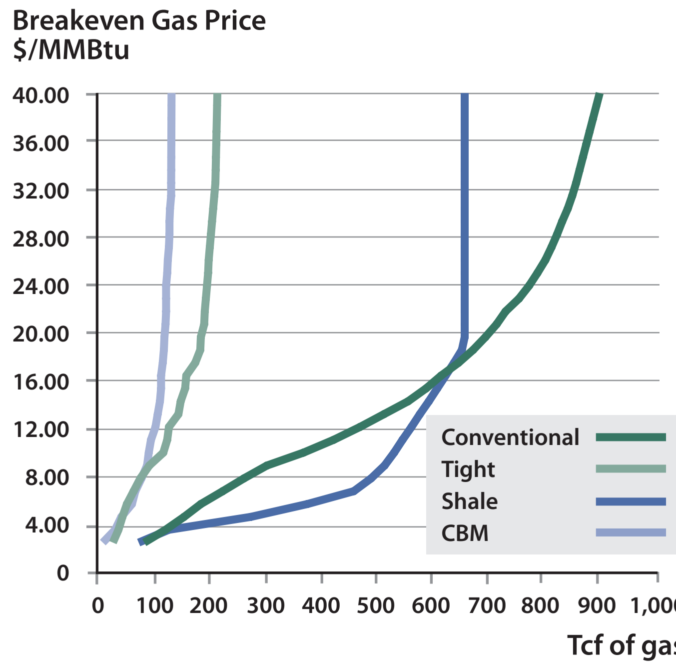
Source: National Petroleum Council 2003; United States Geological Survey 2010; Minerals Management Service 2006; Potential Gas Committee 2007; Potential Gas Committee 2009; Energy Information Administration 2009

**Figure 2.14a Volumetric Uncertainty of U.S. Gas Supply Curves; 2007 Cost Base**




Source: MIT; ICF North American Hydrocarbon Supply Model

**Figure 2.14b Breakdown of Mean U.S. Gas Supply Curve by Type; 2007 Cost Base**




Source: MIT; ICF North American Hydrocarbon Supply Model

Figure 2.14a represents the supply curves for the aggregate of all U.S. resources, depicting the mean estimate and the considerable range of uncertainty. Figure 2.14b illustrates the mean supply curves, broken down by resource type. It clearly shows the large remaining conventional resource base, although it is mature and some of it will require high gas prices to become economical to develop. These curves assume current technology. In practice, future technology development will enable these costs to be driven down over time, allowing a larger portion of the resource base to be economically developed.

Figure 2.14b also demonstrates the considerable potential of shale supplies. Using a 2007 cost base, a substantial portion of the estimated shale resource base is economic at prices between $4/MMBtu and $8/MMBtu. As we see in the current U.S. gas markets, some of the shale resources will displace higher-cost conventional gas in the short to medium term, exerting downward pressure on gas prices.

Despite the relative maturity of the U.S. gas supply, estimates of remaining resources have continued to grow over time — with an accelerating trend in recent years, mainly attributable to unconventional gas, especially in the shales.

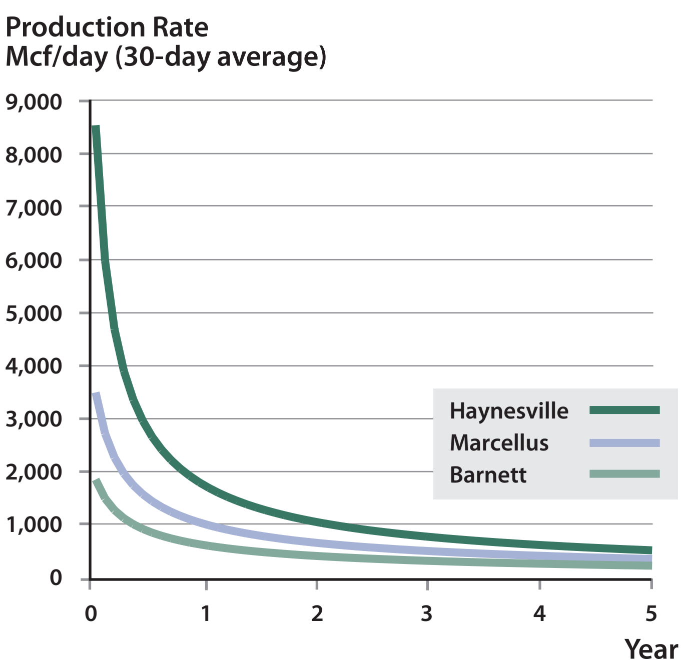
The PGC, which evaluates the U.S. gas resource on a biannual cycle, provides perhaps the best historical basis for looking at resource growth over time. According to this data, remaining resources have grown by 77% since 1990, despite a cumulative production volume during that time of 355 Tcf.

As a subset of this growth process, the application of horizontal drilling and hydraulic fracturing technology to the shales has caused resource estimates to grow over a five-year period from a relatively minor 35 Tcf (NPC, 2003), to a current estimate of 615 Tcf (PGC, 2008), with a range of 420 to 870 Tcf. This resource growth is a testament to the power of technology application in the development of resources, and also provides an illustration of the large uncertainty inherent in all resource estimates.

*According to Potential Gas Committee data, U.S. natural gas remaining resources have grown by 77% since 1990, a testament to the power of technology, and an illustration of the large uncertainty inherent in all resource estimates.*

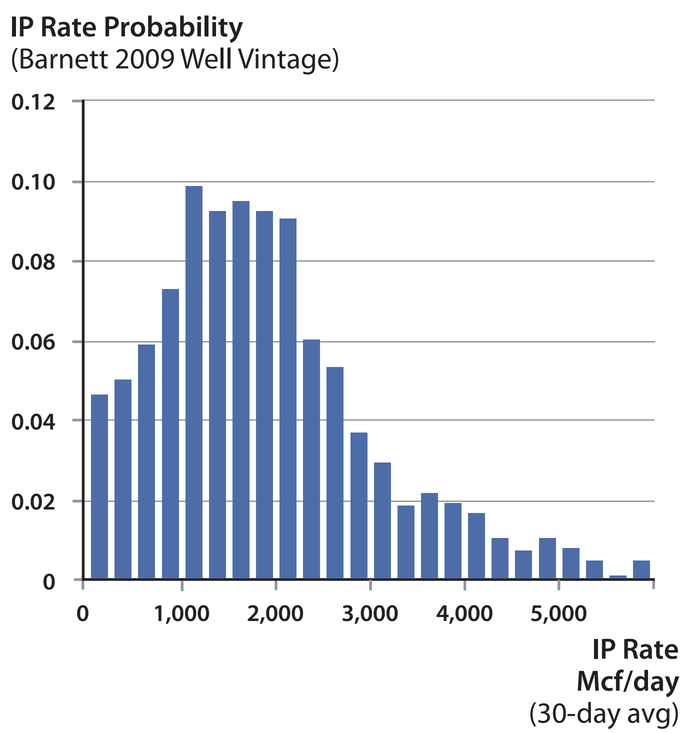
The new shale plays represent a major contribution to the resource base of the U.S. However, it is important to note that there is considerable variability in the quality of the resources, both within and between shale plays. This variability in performance is incorporated in the supply curves on the previous page, as well as in Figure 2.15. Figure 2.15a shows initial production and decline data from three major U.S. shale plays, illustrating the substantial differences in average well performance between the plays. Figure 2.15b shows a probability distribution of initial flow rates from the Barnett formation. While many refer to shale development as more of a "manufacturing process," where wells are drilled on a statistical basis — in contrast to a conventional exploration, development and production process, where each prospective well is evaluated on an individual basis — this "manufacturing" still occurs within the context of a highly variable subsurface environment.

**Figure 2.15a Illustration of Variation in Mean Production Rates between Three Shale Plays**




Source: MIT analysis; HPDI production database and various industry sources

**Figure 2.15b Illustration of Variation in Initial Production Rates of 2009 Vintage Barnett Wells**




Source: MIT analysis; HPDI production database and various industry sources

This high level of variability in individual well productivity clearly has consequences with respect to the variability of individual well economic performance.[13] This is illustrated in Table 2.2, which shows the variation in break-even gas price as a function of initial productivity for the five major U.S. shale plays. The P20 30-day initial production rate represents the rate that is equaled or exceeded by only 20% of the wells completed in 2009; the P80 represents the initial rate equaled or exceeded by 80% of completed wells.

Another major driver of shale economics is the amount of hydrocarbon liquid produced along with gas. The results in Table 2.2 assume dry gas with no liquid co-production; however, some areas contain wet gas with appreciable amounts of liquid, which can have a considerable effect on the breakeven economics — particularly if the price of oil is high compared to the price of gas.

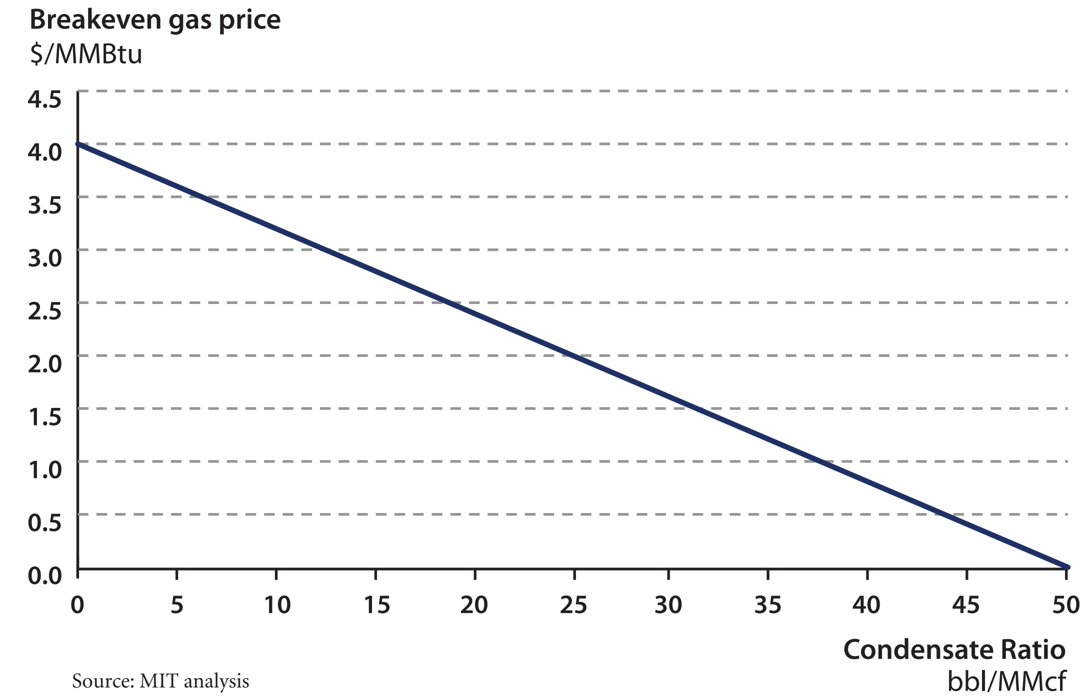
The liquid content of a gas is often measured in terms of the "condensate ratio," expressed in terms of barrels of liquid per million cubic feet of gas (bbls/MMcf). Figure 2.16 shows the change in breakeven gas price for varying condensate ratios in a typical Marcellus well,[14] assuming a liquids price of $80/bbl. It can be seen that for a condensate ratio in excess of approximately 50 bbls/MMcf in this particular case, the liquid production alone can provide an adequate return on the investment, even if the gas were to realize no market value.

**Table 2.2 Full-Cycle 2009 Well Vintage P20, P50 and P80 30-Day Average Initial Production (IP) Rates and Breakeven Prices (BEP) for Each of the Major U.S. Shale Plays Assuming Mid Case Costs**

| | Barnett | | Fayetteville | | Haynesville | | Marcellus | | Woodford | |
|---|---|---|---|---|---|---|---|---|---|---|
| | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf |
| P20 | 2700 | $4.27 | 3090 | $3.85 | 12630 | $3.49 | 5500 | $2.88 | 3920 | $4.12 |
| P50 | 1610 | $6.53 | 1960 | $5.53 | 7730 | $5.12 | 3500 | $4.02 | 2340 | $6.34 |
| P80 | 860 | $11.46 | 1140 | $8.87 | 2600 | $13.42 | 2000 | $6.31 | 790 | $17.04 |

Source: MIT analysis

**Figure 2.16 Estimated Breakeven Gas Price ($/MMBtu) for a Mean Performing 2009 Vintage Marcellus Shale Well, with Varying Condensate Ratio (bbl/MMcf), Assuming a Liquids Price of $80/bbl**




Source: MIT analysis

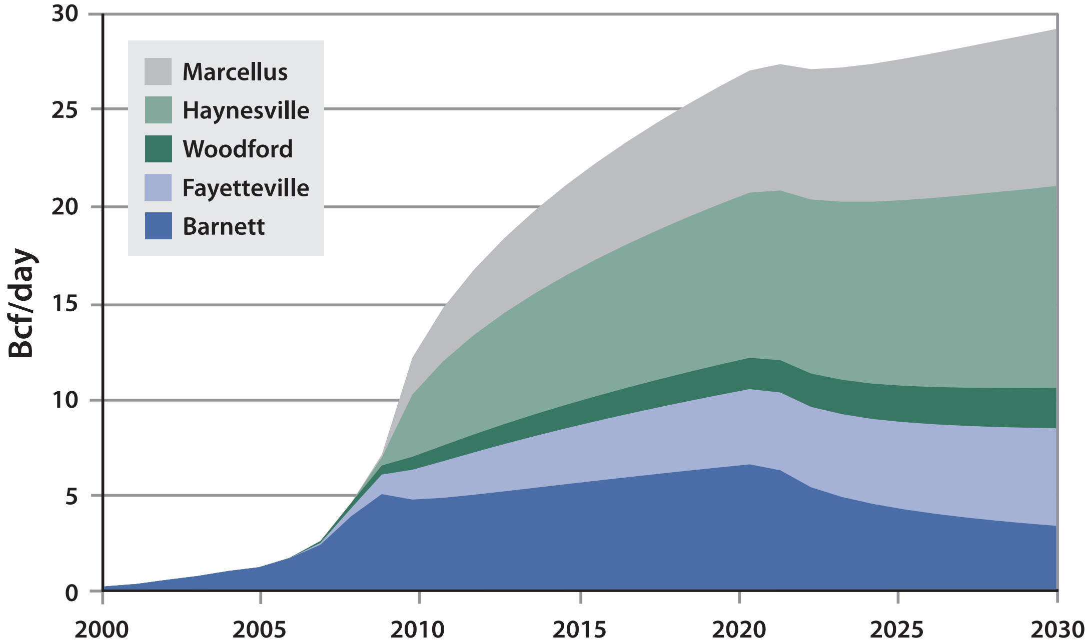
The effects described above create an interesting dynamic in U.S. gas supply. Gas prices have been driven to low levels in 2009 and 2010, at least in part as a result of the abundance of relatively low-cost shale gas. Meanwhile oil prices, determined by global market forces, have remained high. This has led producers to seek liquid rich gas plays, such as certain areas of the Marcellus or the Eagle Ford play in Texas, where condensate ratios can be well in excess of 100 bbl/MMcf. These plays then enable more gas production, even at low gas prices, thus putting further downward pressure on gas prices.

In addition to understanding the resource volumes, it is important to understand the contribution that the new shale resources could make to the overall production capacity within the U.S.

Figure 2.17 indicates how production from the top five shale plays might grow, if drilling were to continue at 2010 levels for the next 20 years. This illustrates the very significant production potential of the shale resource.[15] The current rapid growth in shale production can continue for some time — but in the longer run production growth tapers off as high initial production rates are offset by high initial decline rates, and the quality of drilling prospects declines as the plays mature.

The large inventory of undrilled shale acreage, together with the relatively high initial productivity of many shale wells, allows a rapid production response to any particular drilling effort, provided that all wells can be completed and tied in. However, this responsiveness will change over time as the plays mature, and significant drilling effort is required just to maintain stable production against relatively high inherent production decline rates.

**Figure 2.17 Potential Production Rate that Could Be Delivered by the Major U.S. Shale Plays up to 2030 — Given 2010 Drilling Rates and Mean Resource Estimates**




Source: MIT analysis

## UNCONVENTIONAL GAS SCIENCE AND TECHNOLOGY[16]

Each unconventional gas resource type — tight gas, CBM and shale — presents it own production challenges, although they also share some common characteristics. In particular, all three types have low intrinsic permeability within the rock matrix itself — and thus require enhancement of the connectivity between the reservoir and the wellbore to enable gas flow at commercial rates. A second common characteristic is that the resources tend to be distributed over large geographical areas, saturating pore space often hundreds of square kilometres in areal extent, rather than within the tightly defined boundaries of conventional gas reservoirs. This means that exploration risk is very low; the challenges lie in achieving commercial production rates.

Shale resources represent a particular challenge, because of their complexity, variety and lack of long-term performance data. In conventional reservoirs, there is a long history of production from a wide variety of depositional, mineralogical and geomechanical environments, such that analogues can be developed and statistical predictions about future performance can be developed. This is not yet the case in the shale plays.

Gas shales refer to any very fine-grained rock capable of storing significant amounts of gas. Gas may be present as free gas stored in the natural fracture and macroporosity, adsorbed onto the kerogen[17] and internal surfaces of the pores or dissolved in the kerogen and bitumen. The highly variable definition of gas shales has led to uncertainty in defining controlling factors that constitute an economic development. Values of the key parameters used in identifying potential shale resources vary widely between shale plays, making it difficult to apply analogues and expand shale gas exploration and development outside established basins.

Production in shales is a multi-scale and multi-mechanism process. Fractures provide the permeability for gas to flow, but contribute little to the overall gas storage capacity. The porosity of the matrix provides most of the storage capacity, but the matrix has very low permeability. Gas flow in the fractures occurs in a different flow regime than gas flow in the matrix. Because of these differing flow regimes, the modeling of production performance in fractured shale formations is far more complex than for conventional reservoirs, and scaling modeling results up to the field level is very challenging. This in turn makes it difficult to confidently predict production performance and devise optimal depletion strategies for shale resources.

Production behavior in shale wells is marked by a rapid decline from initial production rates, as seen in Figure 2.15a. Early gas production is dominated by free gas depleted from the fractures and the macroporosity. This rapid initial decline is followed by a long term, much slower decline. As the pressure is lowered, gas desorbs from the organic matter in the matrix and diffuses into the fracture system. During this stage, desorption and diffusion through the matrix drive production. The long-term production behavior of a shale gas well is dependent on the time scale of flow from the matrix relative to flow in the fracture network.

In addition to the complexities of modelling performance, core analysis techniques developed for conventional gas, CBM and tight gas do not work well in shale reservoirs, because they implicitly assume that the same production mechanisms are applicable. The determination of initial parameters such as permeability, porosity and initial gas-in-place can be misleading, contributing to uncertainty in resource size and production performance.

In order to ensure the optimal development of these important national assets, it is necessary to build a comprehensive understanding of geochemistry, geological history, multiphase flow characteristics, fracture properties and production behavior across a variety of shale plays. It is also important to develop tools that can enable the scaling up of pore-level physics to reservoir-scale performance prediction, and make efforts to improve core analysis techniques to allow accurate determination of the recoverable resource.

**RECOMMENDATION**

**The U.S. Department of Energy (DOE) should sponsor additional Research and Development (R&D), in collaboration with industry and academia, to address some of the fundamental challenges of shale gas science and technology, with the goal of ensuring that this national resource is exploited in the optimal manner.**

### Resource assessment

It is in the national interest to have the best possible understanding of the size of the U.S. natural gas resource. For conventional reservoirs, statistically based resource assessment methodologies have been developed and tested over many years. In contrast, the assessment methodology for the "continuous" unconventional resources is less well developed. There would be real benefit in improving the methodology for unconventional resource assessments.

**RECOMMENDATION**

**The USGS should continue, and even accelerate, its efforts to develop improved assessment methodologies for unconventional resources.**

### Technology

The development of unconventional resources in general, and shale resources in particular, has been enabled by the application of existing technology — horizontal drilling and hydraulic fracturing — in a new setting. The objective is to create very large surface areas in the formation that are in communication with the wellbore. Horizontal wells place 4,000 feet or more of well directly into the formation, while multistage fracturing along the horizontal section then creates additional surface area in communication with the wellbore.

Improvements in drilling and fracturing performance are currently rapid, coming from improved know-how rather than specific technology breakthroughs. The repetitive nature of the shale drilling and completion process provides an ideal environment for continuous improvement of drilling and completion times, and fracturing performance. These improvements can serve to enhance well economics and increase the ultimate resource base.

There are a number of areas of technology development that could enhance unconventional gas recovery in the longer term:

- Drilling — unconventional resources require a high well density for full development. Technology that can reduce well costs and increase wellbore contact with the reservoir can make a significant impact on costs, production rates and ultimate recovery. Multi-lateral drilling, whereby a number of horizontal sections can be created from a single vertical wellbore, and coiled tubing drilling to decrease costs represent potential options for future unconventional gas development.

- $CO_2$ enhanced recovery — simultaneous recovery of natural gas while sequestering $CO_2$ provides an interesting, although as yet unproven, possibility for enhancing gas recovery while reducing environmental footprint. In enhanced CBM production, $CO_2$ injected into the reservoir preferentially displaces methane molecules, allowing for enhanced gas production while storing $CO_2$ permanently in the subsurface. While pilot projects have successfully demonstrated enhanced recovery from this technique, there are significant challenges associated with making this a commercial-scale process.

- Seismic techniques — micro-seismic techniques are now commonly used to estimate the length and orientation of induced fractures in the reservoir during fracturing operations; this technique is useful for improving fracturing effectiveness. At a more macroscopic level, there is a need to develop seismic techniques that allow the characterisation of large areas, to identify formation "sweet spots," natural fracture orientation and other properties that would be invaluable in improving overall resource development.

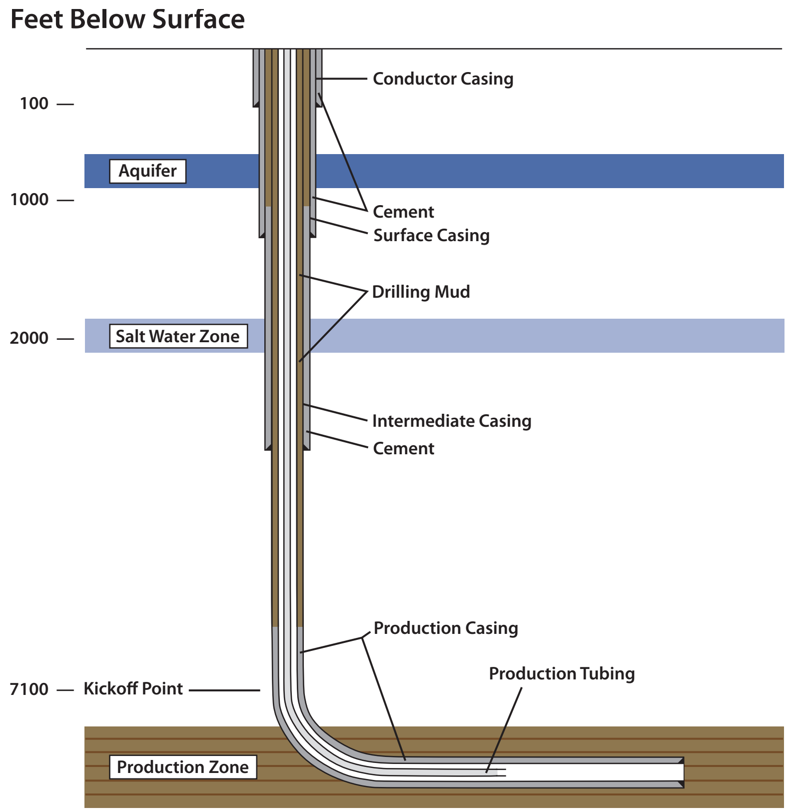
## SHALE GAS ENVIRONMENTAL CONCERNS

### Background

The rapid development of shale gas resources in the U.S. over the past few years has aroused concern, and a perception in some quarters that this development is causing significant environmental problems. A good deal of attention has been focused on the high-volume hydraulic fracturing that is an essential component of shale gas development, with a major concern being that the fracturing process risks injecting toxic fracture fluids into shallow groundwater aquifers, which are in many cases the source of potable water for public use. More broadly, there are concerns about water management and in particular the proper disposal of potentially toxic wastewater from the fracturing procedure.

These concerns have led to restrictions on drilling in some areas and proposed regulatory action. Activity is currently restricted in potentially productive areas of the Marcellus shale in the Delaware River Basin, New York State and Pennsylvania State Forest land. The U.S.

**Figure 2.18 Typical Shale Well Construction** (Not to Scale)




Source: Based on Modern Shale Gas Development in the United States – a Primer

Environmental Protection Agency (EPA) is conducting an extensive review of hydraulic fracturing, and legislation in the form of the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act was introduced in the 2009–2010 Congress.[18]

## The Shale Drilling and Completion Process

In order to appreciate the risks associated with shale development, and to understand appropriate risk mitigation techniques, it is helpful to understand the major steps involved in well construction:

1. Well permitting — states require an operator to obtain a permit to drill a well.

2. Well site construction — typically involves cleaning and grading an area of around four acres in the case of a single well site, or five to six acres in the case of a multi-well site.

3. Drilling and casing — as shown in Figure 2.18, casing is cemented into the well at various stages in order to maintain the integrity of the wellbore, and to ensure that fluids within the various strata are contained within those strata. The drilling and casing process usually entails several stages:

   (i) Drill and set conductor casing — large diameter casing set at shallow depths.

   (ii) Drill through shallow freshwater zones, set and cement surface casing — the most critical phase with respect to the protection of groundwater resources.

   (iii) Drill and cement intermediate casing.

   (iv) Drill and cement production casing.

4. Perforate and fracture the well, usually in multiple stages.

5. Flowback fracture fluid.

6. Place well into production.

### Potential Risks

With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development has for the most part been a good one. Nevertheless, it is important to recognize the inherent risks of the oil and gas business and the damage that can be caused by just one poor operation; the industry must continuously strive to mitigate risk and address public concerns. Particular attention should be paid to those areas of the country which are not accustomed to oil and gas development, and where all relevant infrastructure, both physical and regulatory, may not yet be in place. In this context, the Marcellus shale, which represents 35% to 40% of the U.S. shale resource, is the primary concern.

Within the stages of well construction outlined above, the primary risks are as follows:

1. Contamination of groundwater aquifers with drilling fluids or natural gas while drilling and setting casing through the shallow zones.

2. On-site surface spills of drilling fluids, fracture fluids and wastewater from fracture flowbacks.

3. Contamination as a result of inappropriate off-site wastewater disposal.

4. Excessive water withdrawals for use in high-volume fracturing.

5. Excessive road traffic and impact on air quality.

Before examining these risks in more detail, it is instructive to look at data that attempt to summarize available information on recorded incidents relating to gas well drilling in the U.S. L48 onshore. It is beyond the scope of this study to examine multiple state archives to review individual well incident reports. Instead, to provide a high-level view we have extracted and combined the results from a number of reports that have reviewed drilling-related incidents in the U.S. over the past few years. Table 2.3 indicates the results of this analysis, while Appendix 2E provides a fuller description of the data set. The data set does not purport to be comprehensive, but is intended to give a sense of the relative frequency of various types of incidents.

*With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development has for the most part been a good one — but it is important to recognize the inherent risks and the damage that can be caused by just one poor operation.*

**Table 2.3 Widely Reported Incidents Involving Gas Well Drilling; 2005 – 2009**

| Type of Incident | Number Reported | Fraction of Total |
|---|---|---|
| Groundwater contamination by natural gas or drilling fluid | 20 | 47% |
| On-site surface spills | 14 | 33% |
| Off-site disposal issues | 4 | 9% |
| Water withdrawal issues | 2 | 4% |
| Air quality | 1 | 2% |
| Blowouts | 2 | 4% |

Of the 43 widely reported incidents, almost half appear to be related to the contamination of shallow water zones primarily with natural gas. Another third of reported incidents pertain to on-site surface spills. In the studies surveyed, no incidents are reported which conclusively demonstrate contamination of shallow water zones with fracture fluids.

### The Fracturing Process

The fracturing process entails the pumping of fracture fluids, primarily water with sand proppant and chemical additives, at sufficiently high pressure to overcome the compressive stresses within the shale formation for the duration of the fracturing procedure. Each stage is typically of the order of a few hours. The process increases formation pressure above the critical fracture pressure, creating narrow fractures in the shale formation. The sand proppant is then pumped into these fractures to maintain a permeable pathway for fluid flow after the fracture fluid is withdrawn and the operation is completed.

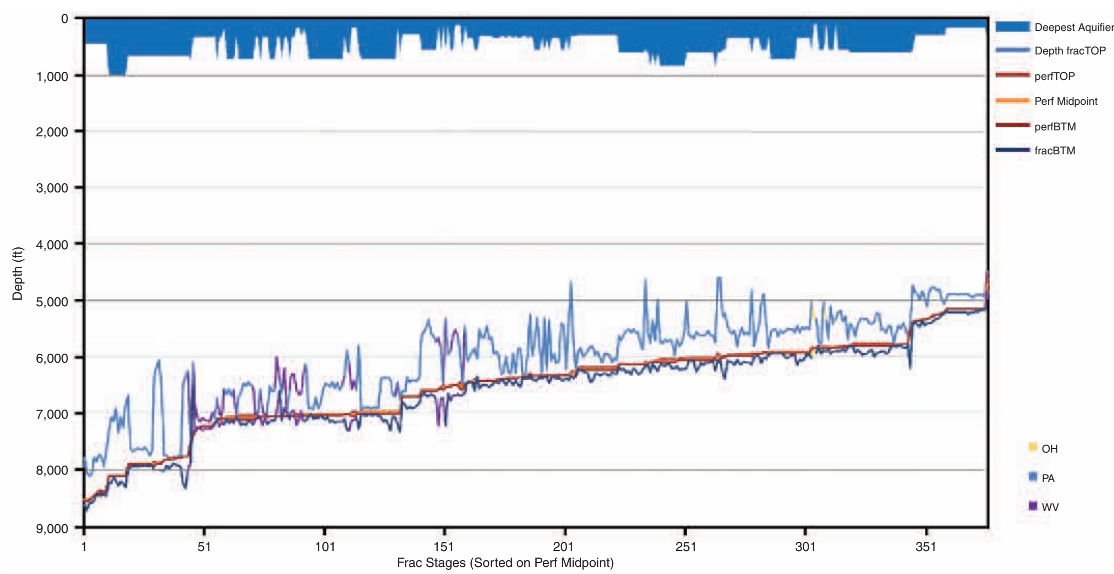
The fracturing process itself poses minimal risk to the shallow groundwater zones that may exist in the upper portion of the wellbore. As described previously, multiple layers of cement and casing protect the freshwater zones as the fracture fluid is pumped from the surface down into the shale formation. This protection is tested at high pressures before the fracturing fluids are pumped downhole. Once the fracturing process is underway, the large vertical separation between the shale sections being fractured and the shallow zones prevents the growth of fractures from the shale formation into shallow groundwater zones. Table 2.4 describes the typical separations in the major shale plays; in all but one case there are several thousand feet of rock — typically sandstones and shales, many of which have very low permeability — separating the fractures shale formation and the groundwater zones. It should be noted here that only shallow zones contain potable water; as depths increase, the salinity of the groundwater increases to the point that it has no practical utility.

A recently published report summarizes the results of a large number of fracturing operations in the Barnett and the Marcellus shales (Fisher, 2010). Figure 2.19 illustrates these results for the Marcellus shale, showing that in all cases the highest growth of the fractures remains separated from the groundwater aquifers by thousands of feet of formation.

**Table 2.4 Separation Distance between Gas Shales and Shallow Freshwater Aquifers in Major Plays**

| Basin | Depth to Shale (ft) | Depth to Aquifer (ft) |
|---|---|---|
| Barnett | 6,500–8,500 | 1,200 |
| Fayetteville | 1,000–7,000 | 500 |
| Marcellus | 4,000–8,500 | 850 |
| Woodford | 6,000–11,000 | 400 |
| Haynesville | 10,500–13,500 | 400 |

**Figure 2.19 Fracture Growth in the Marcellus; Marcellus Shale Mapped Fracture Treatments (TVD)**




Source: Pinnacle Halliburton Service, Kevin Fisher, Data Confirm Safety of Well Fracturing from July 2010

The physical realities of the fracturing process, combined with the lack of reports from the many wells to date of fracture fluid contamination of groundwater, supports the assertion that fracturing itself does not create environmental concerns. However, this simple statement does not address the full range of environmental concerns listed earlier:

1. **Leakage of natural gas or drilling fluids into shallow zones:** this appears to be the most common cause of reported incidents, and it is generally associated with drilling and setting the surface casing. There are three potential risks during this phase of operation: (1) overweight drilling mud causing some drilling fluid leakage into groundwater zones; (2) unexpected encounters with shallow gas zones with the possibility of gas migration into groundwater zones and (3) poor quality cementing of the surface casing, allowing a potential fluid pathway into the groundwater zones during subsequent operations. The protection of groundwater aquifers is one of the primary objectives of state regulatory programs, and it should be emphasized that good oil field practice, governed by existing regulations, should provide an adequate level of protection from these problems.

Nevertheless, regulations vary by state, as a function of local conditions and historical precedent — best practice involves setting cement all the way to surface, and conducting pressure tests and cement-bond logs to ensure the integrity of the surface casing. A detailed comparison of state-by-state regulation would facilitate the widespread adoption of best practice.

**RECOMMENDATION**

**Conduct an inter-state regulatory review and, within constraints of local considerations, adopt best practice for drilling and high-volume hydraulic fracturing.**

2. **On-site surface spills:** the drilling and completion process involves the handling of many thousands of barrels of fluids on-site, in particular drilling mud and fracture fluids. Spills can occur as a result of failure of equipment such as pumps and hoses; in addition, there is potential for overflow of tanks and surface pits. Issues will arise if the volume of spilled material is such that local waterways could be contaminated. These issues are not specifically associated with the fracturing process, and avoiding spills is a normal part of good oil field management practice. The high volumes of fluid associated with shale fracturing may increase spill potential.

   Again, state regulations stipulate the requirements for protecting surface waters against leaks and spills, with regulation varying from state to state.

   Shale fracture fluid or "slickwater," is largely composed of water, which generally constitutes over 99% of the liquid component. As described in Table 2.5, a number of additives are mixed in with the water to increase the effectiveness of the fracturing operation — these additives will vary as a function of the well type and the preferences of the operators. While there has been concern about the transparency of information as regards the make-up of these additives, there has been considerable progress on this issue. Although precise formulations remain proprietary, information is now becoming available for all the chemical compounds contained within the fluids.

In addition to greater transparency about the compounds, there is also progress towards elimination of the toxic components from the additives.

**RECOMMENDATION**

**Require the complete disclosure of all fracture fluid components.**

**RECOMMENDATION**

**Continue efforts to eliminate toxic components of fracture fluids.**

**Table 2.5 Typical Fracture Fluid Additives**

| Purpose | Chemical | Common Use |
|---|---|---|
| clean up damage from initial drilling, initiate cracks in rock | HCl | swimming pool cleaner |
| gel agents to adjust viscosity | guar gum | thickener in cosmetics, toothpaste, sauces |
| viscosity breakers | ammonium persulfate, potassium, sodium peroxydisulfate | bleach agent in detergent and hair cosmetics |
| biocides | gluteraldehyde, 2,2-dibromo3-nitrilophopionamide | medical disinfectant |
| surfactant | isopropanol | glass cleaner, antiperspirant |
| corrosion inhibitor | n, n-dimethylformamide | pharmaceuticals |
| clay stabilizer | potassium chloride | low sodium table salt substitute |

Source: Kaufman et al. 2008

3. **Off-site wastewater disposal** — another potential issue is the disposal of waste from fracturing operations, in particular the fracture fluid and formation water that is returned from the well when it is back-flowed upon completion of the fracturing operation, prior to start of production. Typically, less than 100% of the injected fluid will be recovered, and it will generally be mixed with some volume of displaced formation brine. This fluid must be disposed of appropriately.

   Every year the onshore U.S. industry safely disposes of approximately 18 billion barrels of produced water. By comparison, a high-volume shale fracturing operation may return around 50 thousand barrels of fracture fluid and formation water to the surface. The challenge is that these volumes are concentrated in time and space.

   The optimum method for disposal of oil field wastewater is injection into a deep saline aquifer through an EPA regulated Underground Injection Control (UIC) water disposal well. Problems can occasionally arise if there are insufficient wastewater disposal wells, as appears to be the case in Pennsylvania. Waste can be disposed of at wastewater treatment plants, but problems can arise if the fluid for disposal is of high salinity or contains other contaminants[19]; this may cause the effluent from the treatment plant to exceed desired limits.

   Much effort is now focused on addressing this issue where disposal problems exist. One approach is to recycle the flow-back fluid: using the flow-back fluid from one well as a component in the fracture fluid of the next well. This has the additional advantage of reducing the total amount of water that must be imported to site. In addition, techniques are also being developed to clean up wastewater prior to disposal.

4. **Water withdrawal** — large quantities of water, typically of the order of 100,000 barrels, are required for high-volume hydraulic fracturing, and this has raised concerns about the impact on local water resources.

   While there may be temporary impacts on local resources, the overall impact is small, as can be seen when the volumes are placed in the context of total water usage. Table 2.6 looks at water usage for shale gas operations as a fraction of total water usage in a number of major shale plays — in all cases shale development water usage represents less than 1% of total water usage in the affected areas.

**Table 2.6 Comparative Water Usage in Major Shale Plays**

| Play | Public Supply | Industrial/ Mining | Irrigation | Livestock | Shale Gas | Total Water Use (Bbbls/yr) |
|---|---|---|---|---|---|---|
| Barnett TX | 82.7% | 3.7% | 6.3% | 2.3% | 0.4% | 11.1 |
| Fayetteville AR | 2.3% | 33.3% | 62.9% | 0.3% | 0.1% | 31.9 |
| Haynesville LA/TX | 45.9% | 13.5% | 8.5% | 4.0% | 0.8% | 2.1 |
| Marcellus NY/PA/WV | 12.0% | 71.7% | 0.1% | <0.1% | <0.1% | 85.0 |

Source: ALL Consulting

Indeed, the "water intensity" of shale gas development, at around 1 gallon of water consumed for every MMBtu of energy produced, is low compared to many other energy sources. By way of contrast, several thousand gallons of water per MMBtu of energy produced can be used in the irrigation of corn grown for ethanol.

Nevertheless, careful planning and coordination is necessary to ensure that episodic water withdrawals do not disrupt local supply sources.

**RECOMMENDATION**

**Prepare integrated regional water usage and disposal plans for the major shale areas.**

**RECOMMENDATION**

**Undertake collaborative R&D to reduce water usage and develop cost-effective water recycling.**

5. **Road traffic and environmental disturbance** — oil and gas operations have the potential to be disruptive to local communities in the field development phase of well drilling and completion, particularly in those areas not accustomed to routine oil field operations. As indicated in Table 2.7, the large volumes of water involved in fracturing operations can create high volumes of road traffic.

It should be emphasized that the large number of traffic movements shown on this table are really worst-case numbers. In particular, re-use of flowback wastewater can and does significantly reduce the road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to site, further reducing the amount of road traffic very substantially.

**Table 2.7 Truck Journeys for a Typical Shale Well Drilling and Completion**

| Activity | 1 Rig, 1 Well | 2 Rigs, 8 Wells |
|---|---|---|
| Pad and Road Construction | 10 – 45 | 10 – 45 |
| Drilling Rig | 30 | 60 |
| Drilling Fluid and Materials | 25 – 50 | 200 – 400 |
| Drilling Equipment (casing, drill pipe, etc.) | 25 –50 | 200 – 400 |
| Completion Rig | 15 | 30 |
| Completion Fluid and Materials | 10 – 20 | 80 – 160 |
| Completion Equipment (pipe, wellhead, etc.) | 5 | 10 |
| Fracturing Equipment (pump trucks, tanks, etc.) | 150 – 200 | 300 – 400 |
| Fracture Water | 400 – 600 | 3,200 – 4,800 |
| Fracture Sand | 20 – 25 | 160 – 200 |
| Flowback Water Disposal | 200 – 300 | 1,600 – 2,400 |
| Total | 890 – 1,340 | 5,850 – 8,905 |

Source: NTC Consulting

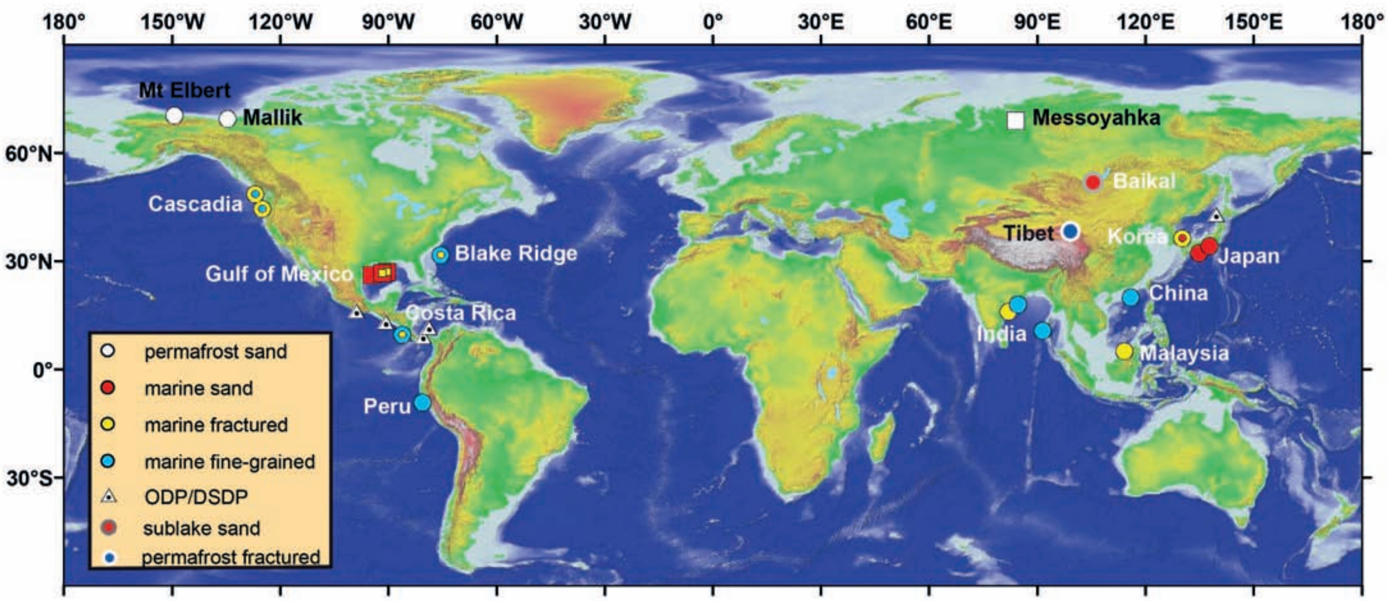
In conclusion, it is clear that oil and gas development is not without risk to the natural environment. State and Federal regulations are designed to mitigate those risks. However, though not the result of risks inherent to the fracturing of shale gas wells, operational errors and poor drilling practice do result in a significant number of incidents. Implementation of the recommendations described above, together with rigorous enforcement of all applicable regulations, should reduce the number of incidents and ensure that shale development can proceed with minimum impact on the environment.

## METHANE HYDRATES[20]

Methane hydrates are not considered in the resource estimates and supply curves described above, as they are still at a very early stage in terms of resource definition and understanding. Nevertheless, gas hydrates could represent a significant long-term resource option, possibly in North America but particularly in some other parts of the world.

Methane hydrates are an ice-like form of methane and water stable at the pressure-temperature conditions common in the shallow sediments of permafrost areas and continental margins. Globally, the total amount of methane sequestered in these deposits probably exceeds 100,000 Tcf, of which ~99% occurs in ocean sediments. Most of this methane is trapped in highly disseminated and/or low saturation methane hydrates that are unlikely to ever be a commercially viable gas source. An estimated 10,000 Tcf may be technically recoverable from high-saturation gas hydrate deposits (Boswell and Collett, 2010), primarily concentrated in permeable (likely sand-rich) sediments.

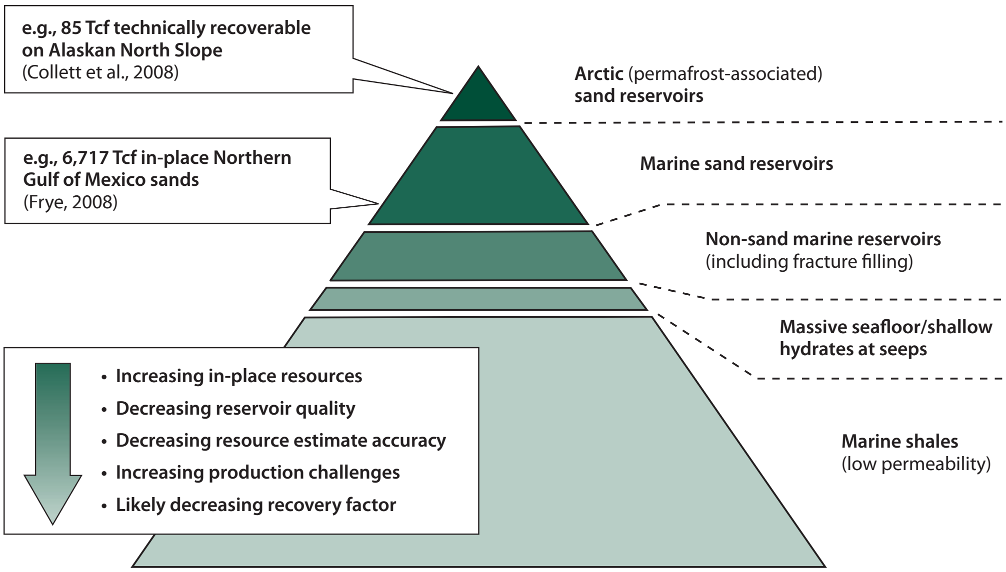
**Figure 2.20 USGS Database of Locations at which Gas Hydrate Has Been Recovered (circles) or Strongly Inferred Based on Drilling-Based Evidence (squares) from Permafrost Areas (black labels) or from Depths Greater than 50 m below the Seafloor (white labels). The color-coding refers to the primary (outer symbol) and, where relevant, the secondary (inner symbol) type of gas hydrate reservoir, using terminology from the gas hydrate resource pyramid (Figure 2.21 in MITEI report). Academic drill sites where deep gas hydrate was recovered but for which reservoir type has not been determined are designated by ODP/DSDP.**




Source: Ruppel, C., Collett, T. S., Boswell, R., Lorenson, T., Buczkowski, B., and Waite, W., 2011, A new global gas hydrate drilling map based on reservoir type, Fire in the Ice, DOE-NETL Newsletter, May edition, vol. 11(1), 13–17.

To date, there have been few formal quantitative assessments of methane sequestered in gas hydrates at regional scales. A recent assessment of in-place resources in northern Gulf of Mexico yielded 6,717 Tcf (median) for sands (Frye, 2008), and other assessments based on similar methodology are expected soon for the U.S. Atlantic Margin and other U.S. margins. The only assessment of technically recoverable methane hydrates ever completed calculated 85.4 Tcf (median) for permafrost-associated gas hydrates on the Alaskan North Slope (Collett et al., 2008). Outside the U.S., the only formal assessment covers ~10% of the area associated with a certain gas hydrates seismic marker in the Nankai Trough and yielded 20 Tcf methane in-place in the high saturation section (Fujii et al., 2008).

**Figure 2.21 The Methane Hydrate Resource Pyramid, After Boswell and Collett (2006)**




Source: After Boswell and Collett (2006)

Several research challenges remain before gas hydrate assessments become routine. The greatest need is geophysical methods that can detect gas hydrates and constrain their *in situ* saturations more reliably than seismic surveys alone and less expensively than direct drilling and borehole logging. Electromagnetic (EM) methods have shown some promise in deep marine settings, but refinements in seismic techniques (e.g., full waveform inversions, seismic attribute analysis) may yet prove even more useful than routinely combining EM and seismic surveys.

Methane hydrates are unlikely to reach commercial viability for global markets for at least 15 to 20 years. Through consortia of government, industry and academic experts, the U.S., Japan, Canada, Korea, India, China and other countries have made significant progress on locating and sampling methane hydrates. No short-term production test has ever been attempted in a marine gas hydrate setting, but several short-term tests (few hours to a few days) have been completed in permafrost-associated wells in the U.S. and Canadian Arctic. Before 2015, the first research-scale, long-term (several months or longer) production tests could be carried out by the U.S. DOE on the Alaskan North Slope and by the Japanese MH21 project for Nankai Trough deepwater gas hydrates. The goals of these tests are to investigate the optimal mix of production techniques to sustain high rates of gas flow over the lifetime of a well and to assess the environmental impact of production of methane from gas hydrates.

*Methane hydrates are unlikely to reach commercial viability for global markets for at least 15 to 20 years.*

Producing gas from methane hydrates requires perturbing the thermodynamic stability conditions to drive dissociation (breakdown) of the deposits into their constituent gas and water. The gas can then be extracted using well-established production methods. Depressurization of the formation is the preferred technique for driving gas hydrate dissociation since it yields a relatively sustainable and well-controlled flow of gas. Thermal stimulation through direct heating or injection of heated fluids can be used to drive episodic dissociation during longer-term depressurization, but requires significant energy expenditure. Injection of inhibitors (e.g., seawater or some chemicals) can also dissociate gas hydrates in the formation, although this technique has numerous disadvantages and is unlikely to be practical at large scales. A final production method will be tested on the Alaskan North Slope in 2012 by ConocoPhillips and could in theory produce methane as well as sequester $CO_2$: $CO_2$ injected into methane hydrate deposits should liberate methane while simultaneously trapping the $CO_2$ within stable gas hydrates (Yezdimer et al., 2002; Farrell et al., 2010).

At present, most conventional oil and gas producers avoid intersecting gas hydrate deposits to prevent long-term damage to the borehole due to unintended dissociation. Producing gas from methane hydrates will instead require targeted drilling into high-saturation deposits and careful management of potentially large amounts of co-produced water. The depths at which gas hydrate occurs are shallower than those associated with (deepwater) conventional gas, rendering gas hydrate well control less of a challenge. Gas hydrate dissociation is also a self-regulating process in most cases, so there is little danger of runaway dissociation. Changes in bulk sediment volume and sediment strength are expected if high-saturation gas hydrates are dissociated, but the impact of these changes will depend on many factors, including the geologic setting, the depth of the deposits and the fate of produced water. In short, the risks associated with gas production from methane hydrates located beneath permafrost or deep within marine sediments are either largely known from existing gas operations or considered manageable.

**RECOMMENDATION**

**Continue methane hydrates research program to develop methods for remote detection of highly concentrated deposits; conduct formal resource assessments; and prove the resource potential through long-term production testing.**

## APPENDICES

2A: Additional resource data tables and maps
2B: Methodology for creating resource ranges
2C: Additional supply curves and background information
2D: Shale gas economics
2E: Analysis of reported gas drilling incidents

## SUPPLEMENTARY PAPERS ON MITEI WEBSITE:

SP 2.1 Natural Gas Resource Assessment Methodologies – Dr. Qudsia Ejaz
SP 2.2 Background Material on Natural Gas Resource Assessments with Major Resource Country Reviews – Dr. Qudsia Ejaz
SP 2.3 Role of Technology in Unconventional Gas Resources – Dr. Carolyn Seto
SP 2.4 Methane Hydrates – Dr. Carolyn Ruppel

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## NOTES

[1]Thermogenic gas is formed by the application of heat and pressure on organic matter; natural gas can also be formed through a biogenic process, in which microbial action in an anaerobic (oxygen free) environment creates methane from organic matter — for example, in swamps, land-fills and shallow formations. This chapter of the report is focused on thermogenic gas.

[2]Permeability is a measure of the ability of a porous medium, such as that found in a hydrocarbon reservoir, to transmit fluids, such as gas, oil or water, in response to a pressure differential across the medium. In petroleum engineering, permeability is usually measured in units of millidarcies (mD). Unconventional formations, by definition, have permeability less than 0.1mD.

[3]ICF International is a consulting firm whose services were used in preparation of supply curves for this study.

[4]In the US, natural gas volumes are typically measured in Standard Cubic Feet (Scf), where the volume is measured at a temperature of 60°F and a pressure of one atmosphere (14.7 pounds per square inch). 1 trillion cubic feet (Tcf) = 1,000,000,000,000 (or $10^{12}$) Scf. Outside North America, natural gas volumes are typically measured in cubic meters. 1 cubic meter ≈ 35.3 cubic feet.

[5]Appendix 2A provides additional maps and detailed data tables concerning gas resource estimates. Supplementary Paper SP 2.2 "Background Material on Natural Gas Resource Assessments with Major Resource Country Reviews," by Dr. Qudsia Ejaz, published on the MITEI website, provides additional material.

[6]Appendix 2B provides details on the methodology used to create the uncertainty estimates shown in this chapter.

[7]Appendix 2C provides further details of cost curves prepared for this study.

[8]Supply curves shown here are based on oil field costs in 2007. There has been considerable oil field cost inflation, and some recent deflation, in the last 10 years. We have estimated cost curves on a 2004 base (the end of a long period of stable costs) and a 2007 base (reasonably comparable to today's costs, 70% higher than the 2004 level, and continuing to decline).

[9]Appendix 2A contains further details on global unconventional resources.

[10]Rogner, "An Assessment of World Hydrocarbon Resources", 1997.

[11]At the time of writing, new more detailed estimates of global unconventional resources are starting to be published. See, for example, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*. Produced by Advanced Resources International (ARI) for the U.S. EIA April 2011.

[12]Appendix 2A provides additional maps and detailed data tables concerning gas resource estimates.

[13]Appendix 2D contains a detailed discussion of the economic performance of the major U.S. shale plays.

[14]These are illustrative calculations only, not based on actual "wet" well performance. The calculations assume that well performance, costs, etc., are unchanged by increasing levels of liquids production. In practice, gas production may be affected by liquid co-production.

[15]This is not a forecast of production — but rather an illustration of the production potential at an assumed drilling rate and assuming a median estimate of resources.

[16]A detailed discussion of the science and technology of unconventional gas resources can be found in the Supplementary Paper SP 2.3 "Role of Technology in Unconventional Gas Resources," by Dr. Carolyn Seto, published on the MITEI website.

[17]Kerogen and bitumen are comprised of organic matter that occurs in hydrocarbon source rocks, formed from the application of heat and pressure to buried organic material over geological time. Kerogen is insoluble in normal organic solvents, while bitumen is soluble.

[18]The Fracture Responsibility and Awareness of Chemicals (FRAC) Act of 2009 proposed to regulate fracturing under the Underground Injection Control provisions of the Safe Water Drinking Act, and to mandate full disclosure of the chemical constituents of all fracture fluid additives. The Bill did not make it out of Committee during the 2009–2010 session of Congress.

[19]Flowback fluid can contain: dissolved solids (chlorides, sulfates, and calcium); metals (calcium, magnesium, barium, strontium) suspended solids; mineral scales (calcium carbonate and barium sulfate); acid producing bacteria and sulfate reducing bacteria; friction reducers; iron solids (iron oxide and iron sulfide); dispersed clay fines, colloids and silts; acid gases (carbon dioxide, hydrogen sulfide); radionuclides (New York Generic Environmental Impact Statement).

[20]A detailed discussion of methane hydrates can be found in the Supplementary Paper SP 2.4 "Methane Hydrates," by Dr. Carolyn Ruppel, published on the MITEI website.