Natural Gas in the United States

[Following are selected excerpts from reports published by the Potential Gas Committee. Text not taken from PGC reports is shown in italics.]

Natural Gas

Natural gas is a combustible, gaseous mixture of simple hydrocarbon compounds, usually found in deep underground reservoirs of porous and permeable rocks. Natural gas is a fossil fuel composed largely of methane. Natural gas is the cleanest burning fossil fuel, producing smaller amounts of combustion by-products than either coal or refined oil products.

The first practical use of natural gas in the United States dates from 1821, in Fredonia, New York, where a crudely drilled well and hollowed-out log pipes were used to deliver gas from a natural gas seep to nearby homes for lighting. Not until the 1880s, however, did natural gas for home heating and lighting and for industrial use become prevalent. By the late 1940s, natural gas had all but replaced the use of "illuminating" gas manufactured from coal and wood. The transition was facilitated in part by federal regulations that discouraged oil field operators from wasting natural gas by venting and flaring. An unknown but likely enormous volume of gas resource was lost through such practices. Nevertheless, natural gas became a marketable commodity, and production flourished. In the years following World War II, the interstate pipeline systems, which was begun in 1925, was greatly expanded, thereby bringing natural gas service to consumers all over the lower 48 United States.

How Natural Gas Forms

According to prevailing scientific theory, the natural gas that is produced commercially today formed millions of years ago when very small plant and animal remains were buried by mud and silt at the bottoms of oceans and lakes. Layers of sediment and plant and animal matter that slowly built up became deeply buried over time until the pressure and heat resulting from the weight of overlying sediment eventually converted this organic matter into natural gas and crude oil. Bacteria also are intimately involved in this generation process, which continues to this day in modern swamps, peat bogs, wetlands, and lakes, large river deltas and in some deep ocean basins. Through time, underground forces cause the buoyant hydrocarbons to move slowly, or migrate, out of their source rocks and into porous and permeable reservoir rocks, where they accumulate and become trapped if impermeable seals are present. Within a given basin or region, these four essential components – source rocks, reservoirs, trapping mechanisms and seal rocks – comprise what geologists call a petroleum system, which may contain oil alone, gas alone, or oil and gas together.

Gas accumulates in two types of reservoirs. Conventional or traditional reservoirs include elastic sedimentary rocks such as porous sandstone, siltstone and conglomerate, and carbonates (limestone and dolomite). Unconventional reservoirs include coalbeds, organic-rich marine and lacustrine (lake-formed) shales and low-permeability sandstones. The grains in these "tight" sandstones have been so pervasively cemented together with silica or carbonate that high-pressure, artificial stimulation or hydraulic fracturing is required to create permeable pathways that allow the gas to flow out of the sand's intergranular pore spaces to the wellbore. Coalbeds and organic rich shales, which are both reservoirs and self-generating source rocks, also usually require stimulation. In rare cases, natural gas has migrated into naturally fractured igneous and metamorphic rocks.

In industry terminology, natural gas occurring alone without oil is called nonassociated gas, whereas associated gas occurs with crude oil. When oil is pumped to the surface, the natural gas within it is released and is referred to as casinghead gas.

Tight Gas Sands

Tight gas sands are continuous reservoirs, in contrast to the discrete reservoirs typically associated with conventional oil and gas production. Other types of continuous reservoirs are methane-producing coal beds and the shale deposits noted below. Tight gas sands reservoirs occur in different types of rocks than the other continuous reservoirs, and their permeability is much lower. Exploration for tight gas sand reservoirs differs from conventional gas exploration in that tight gas sands are continuous, consisting of stacks of sedimentary layers that contain natural gas. The drilling operations in the Piceance Basin visited on the EMFI field program are designed to recover natural gas from the underlyng tight gas sands formations.

Coalbed Methane

Commercial coalbed gas production currently comes from fifteen basins – principally San Juan, Black Warrior (including Cahaba field), Central Applachian, Arkoma, Cherokee, Piceance, Powder River, Raton and Unita. Production from the Northern Appalachian, Forest City, Illinois and Greater Green River (Washakie, Green River, and Sand Wash) basins is still minor but growing. In as-yet non-producing areas, leasing, exploratory drilling, testing and field development are underway in the Pacific, Gulf Coast and Alaska Coal Regions and in the Hanna-Carbon basin (Wyoming) and Maverick basin (Sabinas Coal Region, Texas). Geological investigations of potential coalbed gas occurrences have been conducted in the Black Mesa (Arizona), Denver, North Park (Colorado), and Wind River basins and in the Fort Union Coal Region (North Dakota*). [Coalbed methane represents over 8% of the total U.S. natural gas resource as reported in the PGC 2010 report.]*

Shale Gas

In terms of the four basic components of a "petroleum system," shale is both the source rock and the reservoir rock. Trapping mechanisms are more ambiguous, however, because producible, gas-saturated shales often cover large geographic areas, extending far beyond the productive limits of conventional trapping settings, such as anticlines and faults. Seal rock components are highly variable and can range from bentonites (San Juan Basin) to shale (Appalachian basin and Fort Worth basin) to glacial till (Michigan basin) to shale/carbonate facies changes (Illinois basin).

Economic shale-gas production, typically, if not universally, requires enhancement of shales' inherently low matrix permeability, <0.001 md, which is considerably less than normal "tight" reservoirs such as low-permeability sandstones. Well-completion practices employ hydraulic fracturing technologies to access shale's natural fracture system and to create new fractures. Less than 10 percent of shale-gas wells are completed without some form of reservoir stimulation. Early attempts to fracture these formations employed nitroglycerin, propellants and a variety of hydraulic fracturing techniques. Horizontal wells with multistage completions are now the norm, particularly in the new plays.

As with other unconventional or "continuous-type" gas accumulations, shale-gas systems represent potentially large, technically recoverable natural gas resources, even though past production and proved reserves are still comparatively small.

Until quite recently, gas shales outside North America had received little or no attention. This was attributable both to a lack of understanding of the tight reservoir system itself and to competition with conventional reservoirs currently under development, thus creating a barrier for companies to conduct assessments and pilot projects. Just since PGC's 2006 report, however, the well-publicized success of U.S. shale plays, together with growing gas supply uncertainties, particularly in Europe, have ignited interest in shale-gas prospects in Austria (Vienna basin), England, France, Germany, Hungary, Poland, The Netherlands, Sweden, Australia (Galilee basin, Queensland), New Zealand, China, India, Republic of South Africa, Peru, and Chile.

Note: Producing shale-gas plays in the United States include:

- *Ohio Shale, Applachian Basin*
- *Antrim Shale, Michigan Basin*
- *New Albany Shale, Illinois Basin*
- *Lewis Shale, San Juan Basin*
- *Barnett Shall, Fort Worth Basin*
- *Fayetteville Shale, Arkoma Basin*

Resource Assessments, *2010* *(PGC Press Release dated April 27, 2011)*

[Note: The PGC classifies shale-gas estimates as part of their "traditional" gas resource values because of the historical derivation of this term. In effect, "traditional" connotes "long-established" or "customary" usage rather that a particular classification of reservoir type or, at most, all "non-coalbed" reservoirs.]

The Potential Gas Committee (PGC) today released the results of its latest biennial assessment of the nation's natural gas resources, which indicates that the United States possesses a total resource base of 1,898 trillion cubic feet (Tcf) as of year-end 2010. This is the highest resource evaluation in the Committee's 46-year history, exceeding the previous record-high assessment by 61 Tcf. Most of the increase arose from reevaluation of shale-gas plays in the Gulf Coast, Mid-Continent and Rocky Mountain areas. These changes have been assessed in addition to the 44 Tcf of domestic marketed-gas production recorded during the two-year period since the Committee's previous report.

"The PGC's year-end 2010 assessment reaffirms the Committee's conviction that abundant, recoverable natural gas resources exist within our borders, both onshore and offshore, and in all types of reservoirs—from conventional, 'tight' and shales, to coals," said Dr. John B. Curtis, Professor of Geology and Geological Engineering at the Colorado School of Mines and Director of the Potential Gas Agency there, which provides guidance and technical assistance to the Potential Gas Committee.

Dr. Curtis cautioned, however, that the current assessment assumes neither a time schedule nor a specific market price for the discovery and production of future gas supply. "Assessments of the Potential Gas Committee are 'base-line estimates' in that they attempt to provide a reasonable appraisal of what we consider to be the ‘technically recoverable’ gas resource potential of the United States,” he explained.

The Committee’s year-end 2010 assessment of 1,898 Tcf (statistically aggregated mean value, rounded) includes 1,739 Tcf of gas attributable to “traditional” reservoirs (conventional, tight sands and carbonates, and shales) and 159 Tcf in coalbed reservoirs. Compared to year-end 2008, traditional resources increased by nearly 67 Tcf (4%), while coalbed gas resources declined by 4 Tcf (2.7%), resulting in a net increase in total potential resources of 61.4 Tcf (3.3%).

When the PGC’s results are combined with the U.S. Department of Energy's latest available determination of proved dry-gas reserves, 273 Tcf as of year-end 2009, the United States has a total available future supply of 2,170 Tcf, an increase of 89 Tcf over the previous evaluation.

As Dr. Curtis observed, “Our knowledge of the geological endowment of technically recoverable gas continues to improve with each assessment. Furthermore, new and advanced exploration, well drilling, completion and stimulation technologies are allowing us increasingly better access to domestic gas resources—especially ‘unconventional’ gas—which, not all that long ago, were considered impractical or uneconomical to pursue.”

“Consequently, our present assessment, strengthened by robust domestic production levels and a growing base of proved reserves, demonstrates an exceptionally strong and optimistic gas supply picture for the nation.”

Overall, the Gulf Coast, including the Gulf of Mexico outer continental shelf, slope and deepwater, remains the country’s richest resource area (29 percent of total traditional resources), followed by the Atlantic, Rocky Mountain and Mid-Continent areas, which altogether account for 85% of the assessed total traditional resource. Changes in the assessments from 2008 to 2010 arose primarily from analyses of new geological, drilling, well-test and production data from these same four regions. The largest volumetric and/or percentage increases in individual resource categories (Probable, Possible and Speculative) resulted mainly from reassessments of active and newly developing shale-gas plays in the Gulf Coast Area (La.-Miss.-Ala. Salt Basins, East Texas and Texas Gulf Coast Basins), as well as the Anadarko Basin (Mid-Continent Area), Piceance Basin (Rocky Mountain Area), Appalachian Basin (Atlantic Area) and Michigan Basin (North Central Area).

The growing importance of shale gas is substantiated by the fact that, of the 1,898 Tcf of total potential resources, shale gas accounts for 687 Tcf (“most likely” value), or approximately 36%.

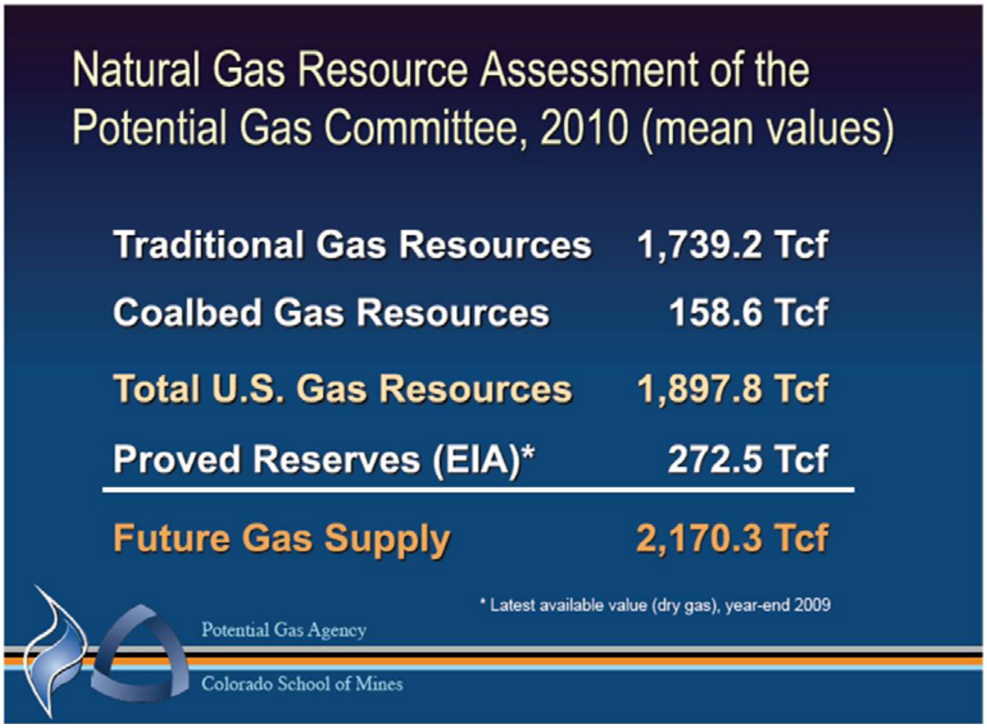

Table 1. U.S. Natural Gas Resource Assessment (Potential Gas Committee, 2010).

About the Potential Gas Committee:

The **Potential Gas Committee** (PGC), an incorporated, nonprofit organization, consists of knowledgeable and highly experienced volunteer members who work in the natural gas exploration, production and transportation industries and in the field and technical services and consulting sectors. The Committee also benefits from the input of respected technical advisors and various observers from federal and state government agencies, academia, and industry and research organizations in both the United States and Canada. Although the PGC functions independently, the **Potential Gas Agency** at the **Colorado School of Mines** provides the Committee with guidance, technical assistance, training and administrative support, and assists in member recruitment and outreach. The Potential Gas Agency receives financial support from prominent E&P and gas pipeline companies and distributors, as well as industry trade and research organizations and unaffiliated individuals.

The above excerpts, taken from recent PGC reports, were prepared by **Dr. John B. Curtis** of the Potential Gas Agency at the Colorado School of Mines and **Mr. Stephen D. Schwochow**, Geological Consultant/Editor in Golden,Colorado.

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