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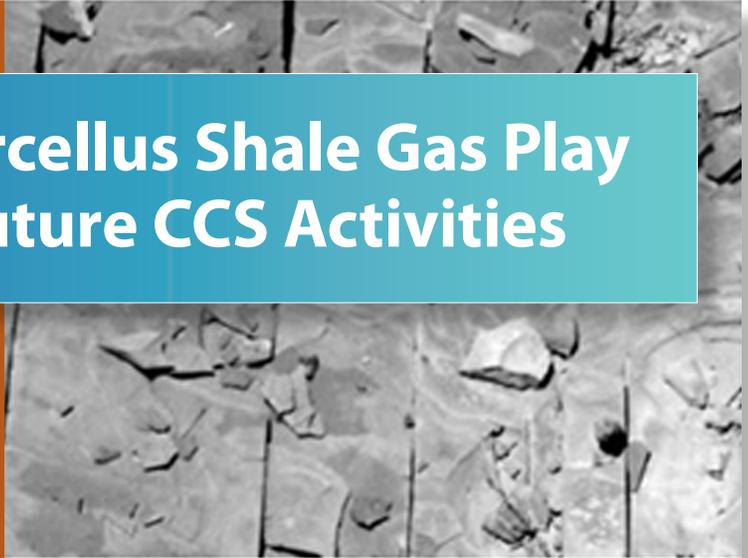## the ENERGY lab

Impact of the Marcellus Shale Gas Play on Current and Future CCS Activities

August 2010

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National Energy Technology Laboratory

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1.0 Introduction

The Marcellus Shale is a major geologic formation underlying significant portions of New York, Ohio, Pennsylvania, and West Virginia. Although it is a very tight formation, it contains a massive quantity of natural gas, thus making it of great economic importance. This paper covers the geology of the Marcellus Shale (extent, depth, gas producing potential, properties, etc.), the techniques used to produce the gas, and the potential for Carbon Capture and Storage (CCS) in the Marcellus Shale or adjacent formations. Because of the low permeability of shale units, hydraulic fracturing and horizontal drilling were developed in the Barnett Shale of Texas during the 1990's; these were the key enabling technologies that made recovery of shale gas economically viable. These technologies have been applied to the Marcellus Shale and other shale gas basins. In addition to gas production from the Marcellus Shale and other gas shale basins in the U.S., this paper discusses the impact of shale gas exploration and production on the potential for CCS in the Marcellus and other units in the Appalachian Basin.

Because of its large extent and volume, as well as the possibility of using some of the existing infrastructure installed for gas production, a major focus of this paper is the potential for CCS in the Marcellus Shale. In considering CCS in relation to the Marcellus Shale, it is important to take into account both the positive and negative impacts of shale gas production. The entire chain of activities involved, not just the injection of carbon dioxide (CO_2), must be examined. In fact, a double chain is involved with the first chain consisting of drilling the gas well, fracturing the formation, producing methane, and pipelining it to market (which could be a power plant). The second chain involves capturing CO_2 from the flue gas of a power plant, transporting it by pipeline to a site in the Marcellus Shale, and ending with injection. This can be represented schematically as shown in Figure 1:
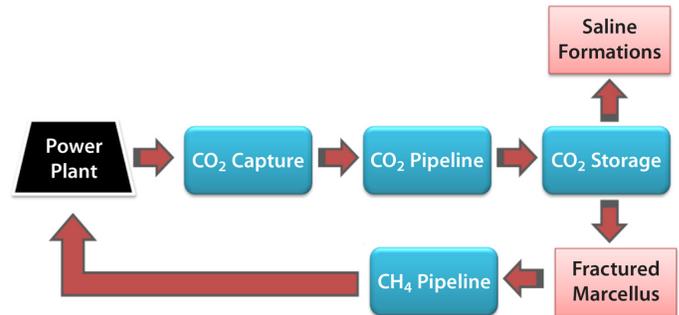
Figure 1. Chain of Activities involved in CCS in relation to the Marcellus Shale.

There are two options for injection: 1) CO_2 could be injected into the depleted Marcellus formation, with the Hamilton and Mahantango shale formations acting as the overlying seals, or 2) CO_2 could be injected into a saline formation below the Marcellus Shale; the Marcellus would act as the primary seal (provided it had not been fractured), and the Hamilton and Mahantango acting as secondary seals.

The CO_2 and CH_4 pipelines could use the same right-of-way. This whole chain needs to be evaluated when considering whether CO_2 storage at a Marcellus Shale site is potentially viable.

Scope: Between 2007 and 2009, domestic natural gas production surged by nearly 15 percent as improvements in two technologies—hydraulic fracturing and horizontal drilling—made it possible to produce shale gas at lower cost than other gas in the supply mix. This increased exploitation of shale gas has opened the possibility of CO_2 storage in these shale formations. This report identifies a broad spectrum of interrelated issues that must be addressed in a coherent manner if one wishes to pursue a viable path towards CO_2 storage in conjunction with shale gas production, particularly in the Marcellus Shale.

2.0 Marcellus Shale Basic Geology – Location and Extent

The Appalachian Basin, approximately 300 miles wide and 600 miles long, encompasses a broad area between the Canadian Shield to the north, the Allegheny front to the east, and the Cincinnati arch to the west (Figure 2) (UTBEG, 2008). The basin represents part of an ancient foreland basin in the Eastern United States that contains complex geology formed by a series of continental plate collisions that resulted in the formation of the Appalachian Mountains and large areas of stretched, faulted, and deformed ridges and valleys (USGS, 1993; UTBEG, 2008). The elongate, asymmetrical northeast-southwest trending central axis of the Appalachian Basin is underlain by a succession of sedimentary rocks greater than 10,000 feet (ft) thick (USGS, 1993; UTBEG, 2008). Several of these strata are porous and permeable sandstones that are potential CO_2 geologic storage targets (Milici, 1996). The central axis of the basin is in the vicinity of Pittsburgh, Morgantown, and Cleveland, areas that have large concentrations of CO_2-producing power plants and other large stationary sources of CO_2 (Figure 2) (UTBEG, 2008).

The black Devonian Shales of the Appalachian Basin, including the carbonaceous Marcellus Shale, have a history of low production and long well life (Harper, 2008). The Middle Devonian Marcellus is highly organic black shale interbedded with medium-gray silty shale and limestone nodules or beds of dark gray-to-black limestone (USGS, 1993). In Pennsylvania, Maryland, and West Virginia the Marcellus Shale contains the Purcell Limestone. The Purcell is composed of gray silty shale interbedded with siltstone, and contains limestone nodules (USGS, 1993).

The Marcellus is the most expansive shale gas play in the U.S., extending on a northeast-southwest trend from west central New York into Pennsylvania, Maryland, Ohio, Virginia, and West Virginia, and covering an area of 95,000 square miles (Figure 2) (Arthur et al., 2008; USDOE, 2009). When the Hamilton Group is undivided, the Marcellus is classified as its basal unit, underlying the Mahantango Formation of the Hamilton in Maryland, New York, and Pennsylvania. In West Virginia, the contact between the Marcellus and the overlying Mahantango brown shales consists of occasional sandstone beds and concretions, or the Marcellus may lie directly below the Harrel Formation

due to a disconformity. This disconformity represents a gap in the geologic record due to either non-deposition or erosion. At its western extent, in eastern Ohio, the Marcellus lies disconformably beneath the Rhinestreet Shale Member of the West Falls Formation (PEP, 2010). The Marcellus Shale typically overlies the Onondaga Limestone; this contact may be sharp, gradational, or erosional (Anderson et al., 1984).

Figure 2. Distribution of the Marcellus Shale Formation.

2.1 Depth, Thickness, and Gas Production Potential

The Marcellus, with an average net thickness in the range of 50 to 100 feet, thins to the north, the west, and the south, and pinches out in eastern Ohio, western West Virginia, and southwestern Virginia. The Marcellus reaches subsurface depths of over 9,000 ft along the preserved basin axis; it outcrops to the east and north and subcrops to the west and south. The estimated production depth between 4,000 to 8,500 feet, together with an average gas content of 60 scf/ton, results in a gas-in-place estimate of up to 1,500 tcf (USGS, 1993; USDOE, 2009). Figure 3 shows the stratigraphic column for the Marcellus Shale.

System	Series	Group	Ohio	West Virginia	Maryland	Pennsylvania	New York
Devonian	Middle	Hamilton	Olentangy	Tully	Tully	Tully	Tully
				Mahantango Fm / Hamilton Gr	Mahantango Fm / Hamilton Gr	Hamilton Gr / Mahantango Fm	Hamilton Gr / Mahantango Fm
				Marcellus	Marcellus	Marcellus	Marcellus
				Tioga Ash Bed	Tioga Ash Bed	Tioga Ash Bed	Tioga Ash Bed
	Lower		Tioga Ash Bed	Onondaga	Onondaga	Onondaga	Onondaga
			Onondaga / Huntersville	Huntersville / Needmore	Huntersville / Needmore	Huntersville / Needmore	Needmore / Bois Blanc
			Oriskany	Oriskany	Oriskany	Oriskany	Oriskany
Silurian	Upper / Middle	Clinton	Keefer	Rochester	Rochester	Rochester	Rochester
			(Clinton Fm)	Keefer	Keefer	Keefer	Clinton Gr
	Lower	Medina	Rose Hill	Rose Hill	Rose Hill	Rose Hill	
			Tuscarora	Tuscarora	Tuscarora	Tuscarora	Tuscarora / Median
Ord	Upper	Queenston					

Legend: **MARCELLUS** / **LIMESTONE** / **SANDSTONE** / **Other Shale/Mix** / **ASH BED** / **CHERT**

Figure 3. Stratigraphic Column for the Marcellus Shale.

2.2 Stratigraphic Units above the Marcellus Shale

Hamilton Group and Mahantango Formation: Conformably overlying the Marcellus Shale is the Hamilton Group to the north and the Mahantango Formation to the south. The Hamilton Group is a dark gray, brown, or green fossiliferous laminated shale and siltstone at the base, which grades into light gray shale and mudstone with some very fine-grained sandstone in the upper section (Martin, 2006; Milici and Swezey, 2006). To the south and west the Hamilton, with an average thickness of 1,000 feet, grades into the silty shales of the Mahantango Formation (Woodrow et al., 1988). The Mahantango Formation is a dark gray, brown, or green fossiliferous siltstone and shale with coarsening upward trends. The thickness of the Mahantango ranges from zero to 1,000 ft (Butts and Edmundson 1966; Berg et al., 1980).

Tully Limestone: The Tully Limestone is a dark-gray to black silty fossiliferous limestone that overlies the Hamilton Group. It extends from southwest New York to southeastern Ohio and into north-central West Virginia and has a maximum thickness of 200 feet (USGS, 1993; Milici and Swezey, 2006). Several unconformities developed in the Tully and zones of pyrite nodules and pyritized fossils have developed where it thins, such as western New York (Woodrow et al., 1988).

2.3 Stratigraphic Units Below the Marcellus Shale

Tioga Ash Bed: The two foot thick Tioga Ash Bed, a regional stratigraphic marker bed, consists of several thin, discrete, volcanic ash falls and often is included as the basal unit of the Marcellus Shale. The Tioga is a gray, brown, black, or green bed with crystal tuff or tuffaceous shale, thinly laminated, with mica flakes

(PEP, 2010). Within the central and northern parts of the Appalachian Basin, the Tioga Ash Bed's basal beds are within the uppermost bed of the Onondaga Limestone. In much of the northern Appalachian Basin the Tioga Ash Bed is the uppermost bed lying within the lowermost part of the Marcellus Shale (Hasson and Dennison, 1988; de Witt et al., 1993; USGS, 1993).

Onondaga Limestone: The widely distributed Onondaga Limestone is a gray or gray-blue crystalline limestone that underlies the Tioga Ash Bed/Marcellus Shale. The Onondaga contains scattered chert nodules and has an average thickness of 200 feet (Hall, 1839; Brett et al., 1994). The contact between the Onondaga and the Tioga/Marcellus may be sharp or gradational (Anderson et al., 1984).

Huntersville Chert and Needmore Shale: Underlying the Onondaga Limestone is the Needmore Shale in the east and the Huntersville Chert to the west (Faill et al., 1989). The Needmore Shale is a green-gray to black shale and dark, thin-bedded fossiliferous argillaceous limestone with a maximum thickness of 200 feet. The Needmore grades laterally westward into the Huntersville Chert in western Pennsylvania and West Virginia (Faill, 1997). The Huntersville is highly silicified black shale with brecciated beds that have been recemented with amorphous silica (Woodward, 1943). The Huntersville also contains white fossiliferous chert, glaucaonitic sandstone, and green-gray siltstone (Bartlett and Webb, 1971). The Huntersville Chert, with an average thickness of 200 ft, is considered an important hydrocarbon reservoir in Pennsylvania, West Virginia, and Maryland (USGS, 1993).

Oriskany Sandstone: The Lower Devonian Oriskany is typically a white to light-gray, fossiliferous quartzarenite cemented with locally-variable amounts of quartz or calcite. It can be traced continuously through New York, Pennsylvania, Ohio, Maryland, West Virginia, Virginia, and Kentucky (Diecchio, 1985; Bruner and Smosna, 2008). The Oriskany typically unconformably overlies strata of the Helderberg Limestone or equivalents, and is overlain by Onondaga Limestone, Huntersville Chert, or Needmore Shale, which vary from limestone to chert to shale and are locally sandy (Diecchio, 1985). The Oriskany is a potential geologic storage reservoir, with an estimated capacity of 7,800 million metric tons CO_2 (MRCSP USDOE, 2007).

Rochester Shale: The Silurian Rochester Shale is a dark gray to black calcareous mudstone and shale that underlies the Lockport Dolomite to the west and the McKenzie Formation to the east. The thickness of the Rochester reaches 65 feet in western New York (Brett et al., 1995). The Rochester Shale could serve as a seal to the underlying Keefer Sandstone and the Tuscarora Sandstone in the event that either one becomes a CO_2 sink.

Keefer Sandstone: The Silurian Keefer Sandstone underlies the Rochester Shale and overlies the Rose Hill Shale. The Keefer has a maximum thickness of over 300 ft in Virginia and thins to the north and southwest (Lampiris, 1976). The Keefer consists of a lower fossilferous iron ore sequence and an upper resistant sandstone unit. The fossiliferous iron ore sequence is gray-red to gray-brown, coarse to very-coarse grained thin bedded calcarenite, and rich in fossils and hematite. The upper unit is white, fine-grained, and thin- to thick-bedded orthoquartzite that is calcareous to the west (Fail et al., 1989). The Keefer is currently being evaluated as a possible CCS target (MRCSP USDOE, 2007).

Rose Hill Shale: The Rose Hill Shale underlies the Keefer Sandstone and conformably overlies the Tuscarora Sandstone. The Rose Hill is 250 to 550 feet thick and consists of fossiliferous dark gray-green or gray-red shale, interbedded with thin fine- to coarse-grained, poorly-sorted, argillaceous sandstone, with a few beds of limestone (Swartz, 1923). The contact with the Keefer Sandstone can be gradational, changing from interbedded shale and calcareous siltstone to fossiliferous hematitic limestone and sandstone (Faill et al., 1989). The Rose Hill Shale and the Rochester Shale may combine to serve as a seal to the underlying Tuscarora Sandstone if it becomes a CCS target.

Tuscarora Sandstone: The Late Ordovician to Early Silurian Tuscarora Sandstone of the Valley and Ridge province of the Appalachian Basin correlates to the Medina Sandstone of the Appalachian Plateau (Faill et al., 1989). The white to light-brown or gray-green Tuscarora is composed of quartzite, quartzarenite, and minor amounts of shale and siltstone (Darton and Taft, 1896; Faill et al., 1989). The Tuscarora, currently being evaluated as a potential CCS target, has an estimated storage capacity of 28,200 million metric tons CO_2 (MRCSP USDOE, 2007).

2.4 Potential Impact on CCS Storage

The continuing development of the Marcellus Shale, one of the largest natural gas plays in the United States, has the potential to both negatively and positively impact the future of CCS in the Appalachian Basin. Although the development of the Marcellus is in the early stages, horizontal well drilling and hydraulic fracturing are key components to production success. Currently, three geologic units are being studied for possible traditional pore space storage of CO_2: (1) the Lower Devonian Oriskany Sandstone; (2) the Middle Silurian Keefer Sandstone; and (3) the Upper Ordovician to Lower Silurian Tuscarora Sandstone (MRCSP DOE, 2007). Due to its low permeability, the Marcellus would serve as one of the seals for these underlying units to effectively prevent vertical migration of injected CO_2. The hydraulic fracturing of the Marcellus has the potential to negatively affect the integrity of this low permeability seal. However, hydraulic fracturing is designed to be confined to a small vertical interval of the Marcellus well above the underlying Oriskany. A well fractured into the Oriskany would be quickly plugged and abandoned due to large water production.

Previous studies (Nuttall et al., 2005a) have successfully demonstrated that organic-rich shale, like the Marcellus formation, may be favorable to adsorb CO_2. There is potential to safely and effectively store CO_2 in the Marcellus formation (and other similar organic shale formations) due to this phenomenon. In addition, a very significant thickness of overlying low-permeability shale and limestone will remain as an effective seal (e.g., the Hamilton Group). However, fracture stimulation could decrease the integrity of the Marcellus which, in turn, could affect containment for storing large volumes of CO_2 in the underlying Oriskany, Keefer, and Tuscarora sandstone units. On the positive side, fracture stimulation and production of shale gas from the Marcellus could create a new class of potential geologic CO_2 storage targets through adsorption trapping on organic material and clay coupled to a value-added process of enhanced gas recovery (See Section 4).
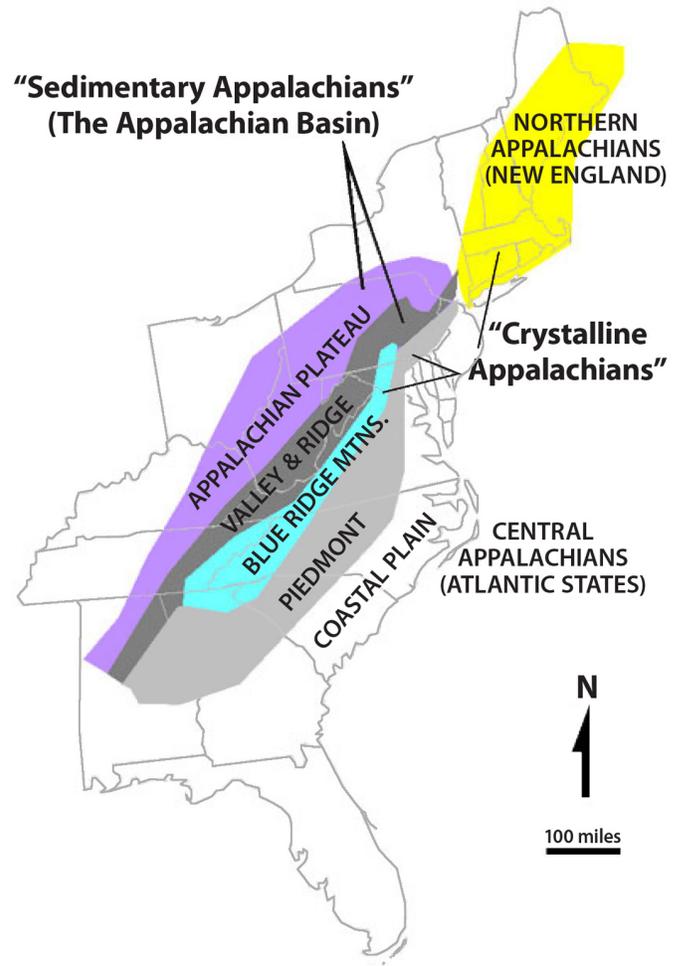

Figure 4. The Appalachian Basin of the United States.
From http://3d3dparks.wr.usgs.gov/nyc/
valleyandridge/sedimentaryapp.htm

3.0 Extraction Techniques

The first commercial shale gas well was drilled in 1821 to a total depth of 27 feet into the Devonian Dunkirk Shale. The gas was used by residents of Fredonia, New York to illuminate their homes. Organically rich gas shale reservoirs were once ignored, but are now the focus of increased drilling activity. The challenge to producing economic quantities of natural gas from shale is to release the gas from rock with very small pores and, as a result, very low permeability. Recent advances in drilling and completions (e.g., horizontal drilling, perforating, and hydraulic fracturing), along with higher gas prices, are making shale gas production economical.

Typical pore spaces in shales are not usually large enough for even small molecules like methane to flow at a rate that would make production economical (Figure 5). Consequently, commercial-scale gas production in shales often requires fracturing to provide adequate permeability for gas extraction. Shales may contain some natural fractures, caused by pressure from overlying rock and the natural movement of tectonic plates, that enable some gas flow; and shale gas has long been produced from shales with natural fractures. Recently, however, there has been significant development of gas shales through techniques that create artificial fractures around well bores (fracture stimulation or fracturing).
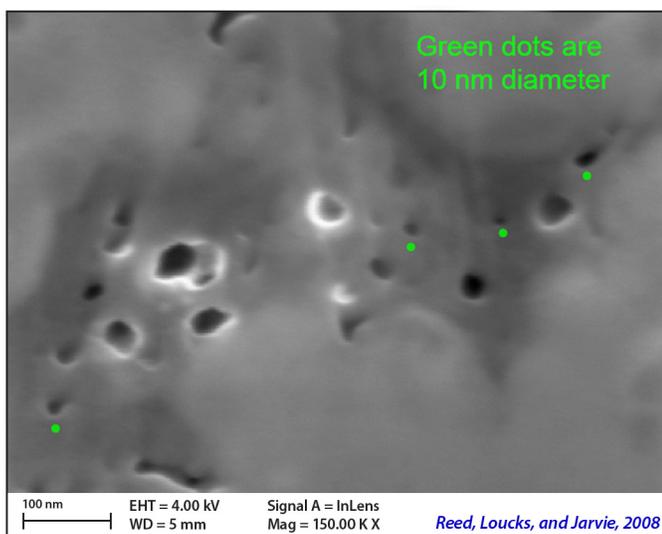
Figure 5. Secondary electron image of nanopores in the Barnett Shale which are so small (20 nanometers) that they impact the passage of methane molecules. Figure attributed to Reed et al., (2008) from Jarvie (2009).

The natural fractures (also known as "joints") in the Marcellus Shale are typically vertically oriented (Figure 6). A vertically-drilled borehole will likely only intersect a few natural fractures, making it difficult to extract shale gas at adequate rates laterally across the formation (Sumi, 2008).
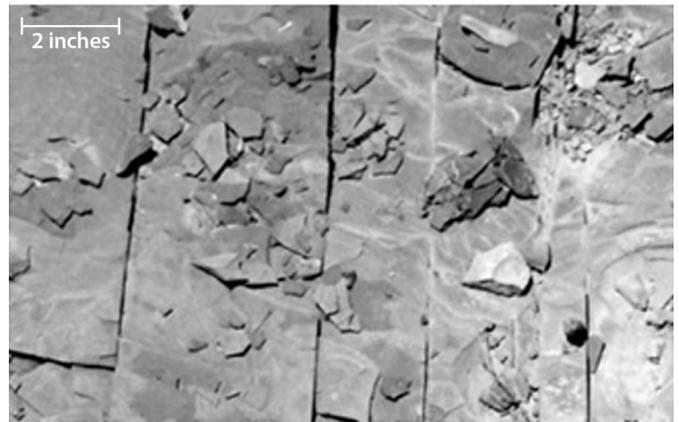
Figure 6. Natural fractures "joints" in Devonian-age shale, typical of fractures in Marcellus Shale. Image from www.geology.com

Most oil and gas reservoirs are much more extensive in their horizontal (areal) dimensions than in their vertical (thickness) dimension. Horizontal wells are used in several gas shale formations to enhance lateral gas extraction (Arthur et al., 2008). Horizontal wells are initially drilled vertically. Then, at some distance above the intended target formation (Marcellus Shale) depth (depending on the radius of curvature), the well begins to curve to achieve a horizontal direction that extends through the target formation laterally (Figure 7). As a result, the wellbore in the shale is perpendicular to the most common fracture orientation, which allows intersects with a greater number of fractures (Geology.com, 2010). High yield wells in the Marcellus Shale have been developed using horizontal drilling and fracture stimulation techniques. Some horizontal wells in the Marcellus Shale have initial flows of millions of cubic feet of gas per day, making them some of the most productive gas wells in the eastern United States. However, the long-term production rates of these wells are not currently known (Sumi, 2008).
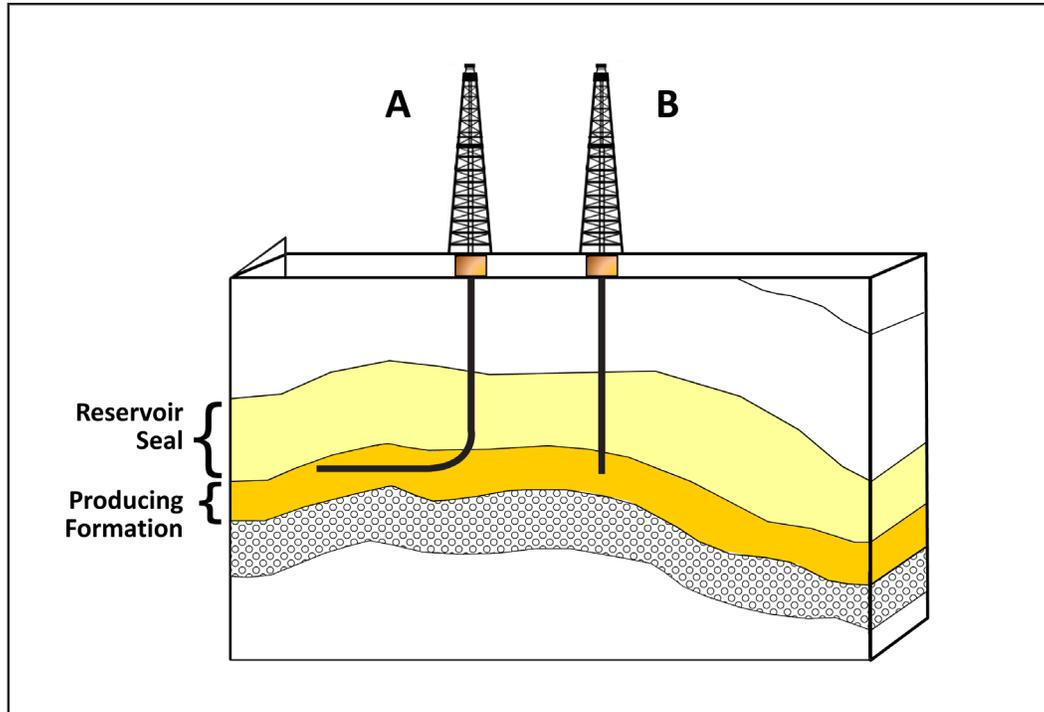
*Figure 7. Greater length of producing formation exposure
to wellbore in a horizontal well (A) vs. a vertical well (B).*
Source: EIA, 1993.

A wide range of factors influence the choice between drilling a vertical or a horizontal well to produce natural gas. While vertical wells may require less capital investment on a per-well basis, production is typically at a lower rate, which could affect profitability. For the Marcellus Shale, a vertical well may be exposed to as little as 50 feet of the gas shale, while a horizontal well may be developed with a lateral wellbore extending 2,000 to 6,000 feet within the 50 to 300 feet thick organic-rich shale (Figure 7).

Horizontal wells have a much reduced aggregate surface "footprint" and subsequent surface disturbance resulting from well pads, roads, and pipelines when compared to the equivalent number of vertical wells. More vertical wells (and the associated surface "footprints") are typically needed to extract the same amount of gas as a given horizontal well in the Marcellus (EIA, 1993). Furthermore, several horizontal wells can be placed on multi-well pads for a less intrusive impact to the surrounding area; the decrease in area can also reduce the impacts from noise, traffic, and result in visual changes to the landscape (Arthur et al., 2008). A vertical well can typically cost as much as $800,000 (excluding pad and infrastructure) compared to a horizontal well that can cost in the range of $2.5 million or more (excluding pad and infrastructure) (Arthur et al., 2008).

3.1 Well Development/Stimulation

As far back as the 1980s, horizontal wells were considered viable options and even drilled in Devonian shale units such as the Marcellus. While most of the wells were technical successes based on drilling and final placement, they were ultimately considered failures due to noncommercial gas production rates. The primary reason for insufficient gas production was that most wells required some form of fracture stimulation, which at the time seemed too costly.

Recent growth of horizontal wells in gas shale (for example, in the Barnett shale) is the result of improvements in fracture stimulation technology. Multistage fracture stimulation treatments are now performed on both horizontal and vertical wells to produce hydraulic fractures around the

borehole. According to Schlumberger (an oil and gas service company), for almost all gas shale wells, the rock around the wellbore must be stimulated through hydraulic fracturing before a well can produce significant amounts of gas (Sumi, 2008). Well stimulation is typically accomplished through hydraulic fracturing of the target formation. After the well is drilled, cased, and cemented to protect groundwater and prevent the escape of natural gas or other fluids, drillers seal off the interval to be fractured and pump large quantities of water mixed with sand and trace chemicals to modify fluid properties into the shale formation under extremely high pressure to fracture the shale around the wellbore. These induced fractures increase the flow of natural gas through the formation to the wellbore. The sand injected with the fracture fluid acts as a propant that prevents the factures from closing once the pressure is reduced.

The amount of water typically required for hydraulic fracturing ranges from approximately one million gallons for a vertical well to approximately five million gallons for a horizontal well (PADEP, 2010). The recovered fracture water must be either reused in other wells or sent offsite to a treatment facility. To protect surface water resources, a number of states in areas of active shale gas development have become concerned with ensuring proper treatment and disposal of fracture water. For example, in West Virginia, the State Senate passed Bill No. 658 amending the Code of West Virginia (Section §22-11-7C) regarding establishing requirements for use of water resources in Marcellus gas well operations. This bill mandates special permit and reporting requirements for Marcellus Shale gas wells using water resources for fracturing or stimulating gas production. Important reporting requirements under Bill No. 658 include the source and amount of water used, water transport method, and the assurance of proper disposal. The ability to economically stimulate the formation along horizontal well bores has made these wells commercial successes. Wells that were previously drilled vertically to access Marcellus or other formations can be reused to drill horizontally through the Marcellus Shale.

3.2 Well Spacing and Placement

Operators developing the Marcellus Shale are currently using both horizontal and vertical wells to extract the natural gas present in the shale. To effectively manage the resource, the low natural permeability of shale requires vertical wells to be developed at closer spacing than for conventional gas reservoirs. Arthur et al., (2008) have estimated that the spacing for vertical wells in the Marcellus start at approximately 40 acres, while future horizontal wells are predicted to be spaced at intervals closer to 160 acres. By applying these predicted well spacings to a standard section (one square mile - 640 acres) of land, 16 vertical wells would be needed; whereas, the same square mile of resource could be produced from as few as 4-6 horizontal wells drilled from a single multi-well pad.

If development in the Marcellus follows trends established in the Barnett Shale, drilling of longer laterals, bigger fracture jobs with more stages, and more infill drilling can be expected, (As a field matures, additional wells—infill wells, or wells between other wells—may be drilled to increase recovery.) In the Barnett, infills are being drilled down to 10 acres, while refracturing of the first horizontal wells from 2003 and 2004 has commenced. Infills and refractures are expected to improve estimated ultimate recovery from 11 percent to 18 percent (Halliburton, 2008). In addition, multilaterals to reduce the number of pads that need to be developed, especially in urban areas, and water recycling are growing trends that reduce operating costs and minimize potential environmental damage.

4.0 Technical Feasibility for Application of CCS Technology

Aside from its economic and fuel resource benefits, the Marcellus Shale offers two possibilities related to geologic storage of CO_2: (1) the Marcellus could act as a sealing (caprock) formation for injection of CO_2 into limestone and sandstone formations below the Marcellus, and (2) the Marcellus itself could act as a storage reservoir for captured anthropogenic CO_2. The Marcellus Formation is regionally extensive, covering large parts of Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia, and parts of Canada. It is also relatively thick (ranging from 40 to 900 feet in thickness), with low porosity (~ 0.09) and permeability (5.9 – 19.6 μd). These characteristics make it an excellent caprock formation for CO_2 injected into deeper formations (Soeder, 1988), provided borehole penetrations and fracturing have not comprimised its integrity. On the other hand, the Marcellus itself is also a possible geologic storage option. The Marcellus is a black, organic-rich shale, which could provide favorable CO_2 adsorption as well as available pore space from formation stimulation/fracturing. In this scenario, additional layers above the Marcellus would act as seals.

4.1 Marcellus as a Geologic Storage Target Formation

Continuous, low-permeability, fractured, organic-rich gas shale units are widespread (Figure 9 in Section 5) and are possible geologic storage targets. As part of a project funded by NETL, drill cuttings and cores from the Upper Devonian organic-rich shale units across Kentucky, West Virginia, and Indiana were sampled, and adsorption isotherms obtained. Sidewall core samples were analyzed for their potential CO_2 uptake and resulting methane displacement. Digital well logs were used to model total organic carbon (TOC) and CO_2 adsorption capacity (Nuttall et al., 2005a, b). Results indicated CO_2 adsorption capacities at 400 psi ranged from a low of 14 scf/ton in less organic-rich zones to more than 136 scf/ton in the more organic-rich zones. There is a direct linear correlation between measured TOC content and the adsorptive capacity of the shale with CO_2 adsorption capacity increasing with increasing organic carbon content.

In shale, natural gas occurs in the intergranular and fracture porosity tend is adsorbed on clay and the surface of organic particles (kerogen). This is analogous to methane recovery in coal beds, where CO_2 is preferentially adsorbed and displaces methane. Organic-rich shale may similarly desorb methane in the presence of CO_2. As a result, enhanced natural gas recovery (EGR) may be possible as stored CO_2 displaces methane in gas shale reservoirs.

This preliminary study mentioned above indicates that organic-rich gas shale can serve as a target for geologic storage of significant volumes of anthropogenic CO_2. Highly carbonaceous black shale is the most likely storage reservoir, and the surrounding shale may serve to seal the reservoir. CO_2 trapping by adsorption in gas shale has a higher probability for containment compared to typical pore filled reservoirs (i.e., the gas is bound to the shale). Initial estimates, based on these data, indicate a geologic storage capacity of as much as 28 billion metric tons in the deeper and thicker parts of the related Devonian Ohio Shale in Kentucky. The potential storage resource has not been computed for the Marcellus Shale, but given the greater depths and higher organic content, it could be extremely large. Organic rich gas shale may prove to be a viable geologic sink for CO_2. The extensive occurrence of organic-rich gas shale in Paleozoic basins across North America would make them an attractive regional target for economic CO_2 storage and enhanced natural gas production.

Technical and economic challenges to CO_2 geologic storage and enhanced gas recovery from shale gas reservoirs include (1) potential reduction of the permeability of already low-permeability shale due to differential swelling, similar to that of coal beds, and (2) the potential negative impact on long-term natural gas production, due to CO_2 contamination of produced methane.

Based on data for the adsorption of CO_2 onto organic shales of 14 scf/ton shale to 136 scf/ton shale at 400 psi and the following Marcellus Formation characteristics,

> Density = 159 lb/ft^3 of shale
>
> Area = 95,000 mi^2
>
> Average Thickness = 100 ft
>
> CO_2 Density$_{Gas}$ = 5.8x10^{-5} scf/ton

the procedure by Nuttall et al. (2005a) can be used to estimate the CO_2 storage potential across the entire Marcellus Formation, which, as a whole, has the potential to store from 17 to 166 billion tons of CO_2.

4.2 Potential Risk Associated with Existing Wells

As with any developed or developing gas or oil field, existing wellbores will be a concern that needs to be addressed. The placement, type, and number of well penetrations can have implications for future geologic storage (GS) opportunities in regions overlying the Marcellus. The Marcellus Shale has potential to serve as a regionally extensive caprock formation based on its extent, thickness, and low porosity and permeability (Soeder, 1988). While these wells provide the opportunity to acquire natural fuel resources, they might create potential leakage conduits for CO_2 injected into either deeper formations (like the Oriskany Sandstone) or into the vacant fractured spaces in the Marcellus Formation, possibly creating avenues for CO_2 to migrate to shallower formations or underground sources of drinking water (USDW). However, this potential concern could be modeled, identified, and mitigated with risk assessment software currently available.

Federal and state regulations under the U.S. EPA Underground Injection Control (UIC) program are in place to mandate the construction, operation, permitting, and closure of injection wells in order to protect drinking water sources. This includes the newly proposed UIC Class VI injection well specific to

geologic storage of CO_2. Future CO_2 injection wells under Class VI, including into or below the Marcellus Formation, will first require the use of detailed computational modeling to define a calculated region surrounding the well (also called the Area of Review (AOR)) that may be impacted by project activity. The proposed rule for Class VI requires identification and evaluation of all artificial penetrations (including existing extraction wells) and other features that may promote the upward migration of fluids. In response, project operations must plug and/or remediate wells within the AOR as appropriate to prevent fluid migration.

Table 1 outlines gas extraction wells in the state of West Virginia permitted and completed between 2003 and 2009; 2,840 wells were reported by the West Virginia Geological and Economic Survey between 2003 and 2009. Of those 2,840 wells, those intended for, or drilled and completed below, the Marcellus total 2,275 gas extraction wells. As indicated by Table 1, target formations at depths below the Marcellus include the Onondaga, the Oriskany, the Helderberg, and the Tuscarora. In Pennsylvania, by comparison, a total of 2,918 well permits issued for gas extraction from the Marcellus Shale were filed from January – July 2009 (DRNR, 2010).

Table 1. Summary of gas extraction wells and target formations reported in the state of West Virginia from 2003 to 2009.
Data provided by the West Virginia Geologic and Economic Survey between 2003 and 2009.

Formation	Formation Type	Top of Formation Depth (feet)	Number of Wells
Big Lime/Injun	Shale/Sandstone/Limestone	4,000 – 6,000	93
Huron/Rhinestreet	Shale	5,000 – 7,000	53
Hamilton Group	Shale	6,000 – 7,000	100
Marcellus	Shale	3,500 – 8,500	2173
Onondaga	Limestone	4,300 – 8,300	28
Oriskany	Sandstone	4,500 – 9,000	45
Helderberg	Limestone	5,500 – 8,800	21
Tuscarora	Sandstone	6,700 – 12,000	8

The state of West Virginia is approximately 24,077 square miles in area, suggesting that at least one gas extraction well (not considering other types of wells) drilled and completed from 2003 – 2009 penetrates the Marcellus Formation (or deeper) every 10.6 square miles. This calculation does not include existing wells in place prior to 2003 (regardless of depth or function) or the fact that more extraction wells can be expected to be drilled into the Marcellus Formation due to promising gas resources. Existing and proposed well distribution is depicted in Figure 8. From an AOR standpoint, CO_2 plume migration typical of a one million tons/yr commercial-scale injection into a high-porosity formation (e.g., Mt. Simon Sandstone) may range from 1 to 1.9 miles from the injection site following plume stabilization (Leetaru et al., 2009).

Newly proposed U.S. EPA Underground Injection Control (UIC) injection wells must account for all existing penetrations within the calculated AOR, several of which may require immediate action to prevent potential leakage. From a federal standpoint, requirements for plugging and abandoning UIC Class I, II and V wells according to 40 CFR 146.10 (minimum AOR radius ¼ mile from injection well) suggest that the well shall be plugged with cement in a manner which will not allow the movement of fluids either into or between underground sources of drinking water. Project operators must develop a corrective action plan to address improperly completed or plugged wells within the AOR and submit it to the responsible regulatory agency for
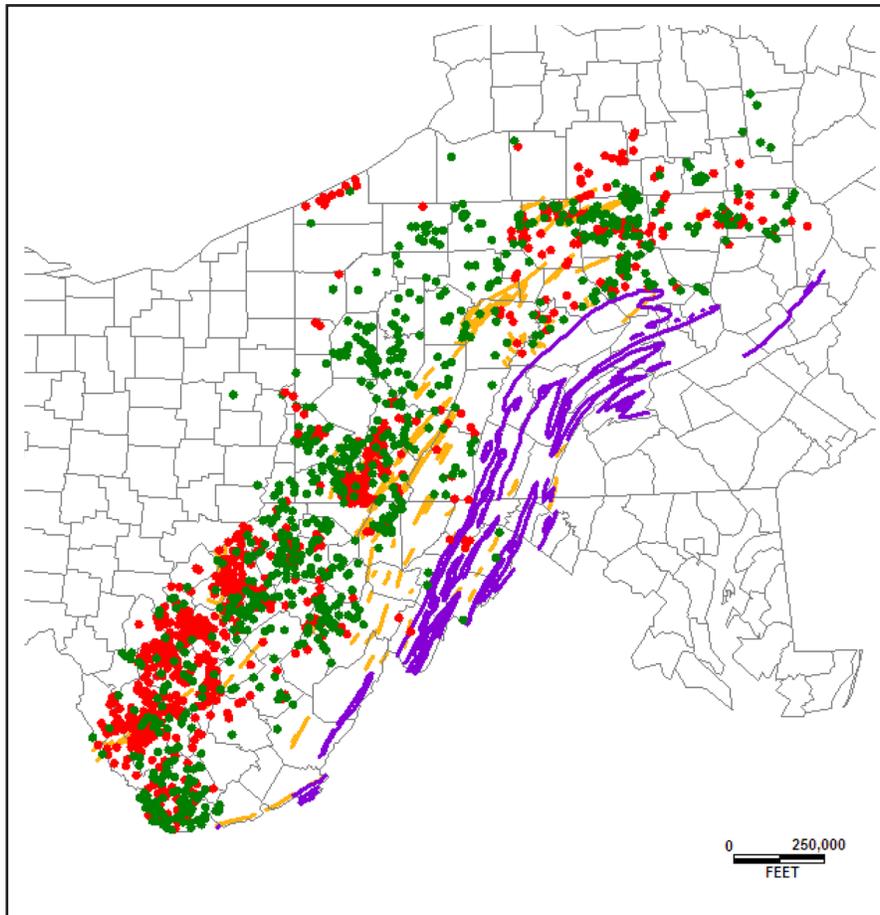
Figure 8: Map of the location of Marcellus Shale natural gas wells as of November 2009. Natural gas wells that are drilled into the Marcellus are indicated by red circles, permitted wells are indicated by green circles. The known Marcellus outcrop belt is shown in purple. Know faults that penetrate the Oriskany Sandstone are shown in orange. Due to the map scale (250,000:1) not all wells are represented on the map.
Source: A Shale Tale, Marcellus Odds and Ends, Gregory Wrightstone of Texas Keystone, presented at the 2010 Winter Meeting of the Independent Oil & Gas Association of West Virginia.

approval. Procedures for cement placement for plugging Class I, II, and V wells, as described by 40 CFR 146.10, include the following methods:

- **Balance method** – Displace the plugging fluid with cement slurry that is placed through the drill pipe or tubing into the wellbore. Tubing is then slowly pulled back out of the top of the cement, leaving behind a solid plug with minimal contamination by the plugging fluid.

- **Dump bailer method** – A bailer is lowered into a well via wireline and releases a predetermined amount of cement at a given depth. A bridge plug or cement basket is typically previously placed at the specified depth.

- **Two-plug method** – This method involves a top plug, bottom plug, and latch-down type plug catcher. Tubing with the plug catcher is lowered to the desired depth. The bottom plug, followed by the desired cement slurry volume, is pumped into the pipe. The top plug is placed on top of the cement slurry followed by a plugging fluid. Tubing can then be removed leaving a solid cement plug behind (USEPA, 1983).

- **Alternative methods approved by the regulating agency**

Proposed Class VI well rules require a calculated AOR that is reassessed over the duration of the project. Computational modeling is used to forecast lateral and vertical migration of the CO_2 plume and formation fluids. This type of AOR determination is different from assigning a fixed radius AOR, which is the method typically required by existing UIC regulations. The proposed rules require that all active or abandoned wells within the calculated AOR must be identified, and necessary corrective action must be taken in order to prevent the movement of fluids into or between USDWs. Operators must submit the following information to the necessary regulating agency: a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, as well as any additional information. Under the proposed rules, owners or operators of Class VI wells must perform corrective action on all wells in the AOR that are determined to need

corrective action using methods necessary to prevent the movement of fluid into or between USDWs, including use of corrosion resistant materials, where appropriate. Well plugging procedures for proposed UIC Class VI wells (40 CFR 146.92) and abandoned wells within the AOR needing corrective action include:

1. Appropriate test or measure to determine bottomhole reservoir pressure

2. Appropriate testing methods to ensure mechanical integrity as specified in 40 CFR 146.89

3. The type and number of plugs to be used

4. The placement of each plug, including the elevation of the top and bottom of each plug

5. The type, grade and quantity of material to be used in plugging; the material must be compatible with the carbon dioxide stream

6. The method of placement of the plugs

In Pennsylvania, the Marcellus Shale natural gas well permit application process requires disclosure of the well location in proximity to coal seams and distances from surface waters and water supplies. The Department of Environmental Protection (DEP) then reviews the application to determine whether the proposed well might cause environmental impacts, conflict with coal mine operations, or exceed well spacing requirements. Operators must submit reports on well completion, waste management, annual production, and well plugging. Pennsylvania law requires drillers to case and cement Marcellus Shale natural gas wells through all fresh water aquifers before drilling through deeper zones known to contain oil or gas. This casing and cement protects groundwater from the fluids and natural gas that will be contained inside the well, and keeps water from the surface and other geologic strata from mixing with and contaminating groundwater (PADEP, 2010).

Table 1 provides some insight into the number of new wells drilled in the Marcellus over a six year period simply for extraction purposes. Combining these data with the number of wells already in place and the anticipation of even more Marcellus

extraction wells in the near future, suggests two conclusions: (1) for future geological storage projects in or below the Marcellus Formation (in all states where the Marcellus is present), the number of wells in any given calculated AOR assessment could be quite large and will involve a significant level of effort (identification, corrective action plan development and submission, and well plugging); and (2) the number of penetrations and disturbances in the Marcellus Formation (Table 2) (including vertical wells, horizontal wells, and fracturing/stimulation) from both existing wells and future gas extraction efforts could significantly degrade the integrity of the Marcellus as a suitable caprock formation for geologic sequestration for formations below the Marcellus. The loss of the Marcellus as a suitable caprock formation could mean a loss of significant CO_2 storage potential in the northeastern part of the United States. However, even if the Marcellus Shale were to be compromised as a caprock through current drilling activities, the overlying shales of the rest of the Hamilton Group, as well as additional overlying shales, would serve to impede upward migration of sequestered CO_2. These overlying shales would have wellbore penetrations, as they must be drilled to reach the Marcellus, but these would be lower areas of leakage risk than the completed portions of the Marcellus.

4.3 Summary – Technical Considerations for Geologic Sequestration Near the Marcellus

As summarized in Sections 4.1 and 4.2, the Marcellus Formation provides potentially both (1) an organic shale formation in which CO_2 injection and storage could be favorable due to the shale's affinity to adsorb CO_2, and (2) a caprock formation for geologic storage of CO_2 into the limestone and sandstone formations below the Marcellus. Other general technical considerations include:

• The possibility of combined CO_2 enhanced gas recovery/CO_2 storage in the Marcellus.

• Conversion of "dry wells" into CO_2 injection wells (following UIC Class VI requirements)

• Existing gas extraction well construction materials (cement, casing, etc.) may not maintain integrity in the presence of CO_2 plumes. Well remediation may be required as part of AOR assessment.

• Some of the shale formations above the Marcellus (Hamilton Group and Mahantango Formation) could serve as potential caprocks to the Marcellus Formation, should the Marcellus be used for CO_2 storage. While these formations may not be exposed to the horizontal well drilling and hydrofracturing to which the Marcellus is exposed to, due to gas exploitation, they will be penetrated by every well drilled to the Marcellus Formation or below.

Table 2: Estimated number of wells anticipated in Marcellus based on published well spacing data.

Marcellus Well Density	
Well Spacing (acres/well)	40 – 160
1 square mile	640 acres
Wells per square mile	4 – 16
Marcellus Area	95,000 mi²
Total Wells	*380,000 – 1,520,000*

5.0 Other Shale Gas Basins

Shale gas reservoir developments are a growing source of natural gas reserves across the United States (Figure 9). Through the use of technology, U.S. gas operators are converting previously uneconomic natural gas resources into proven reserves and increased production. The increase in unconventional gas production illustrates the success of horizontal drilling, fracturing, and completion technologies. This success stems from analysis of geologic and engineering data on decades- to century-old producing areas, identification of unexploited resources, and application of the new drilling and completion technology necessary to convert unconventional resources into reserves.

Across the U.S., numerous geologic basins are recognized as targets for shale gas production; an estimated 35,000 wells were drilled in 2006 (Halliburton, 2008). The Energy Information Administration (EIA) projects that natural gas production from unconventional resources in the United States will increase 35 percent, or 3.2 trillion cubic feet (Tcf), between 2007 and 2030 (EIA, 2009a), with the largest increase expected to come from the development of shale formations in the lower 48 States. Unconventional natural gas production has increased nearly 65 percent since 1998 and has become an increasingly larger portion of total natural gas production, increasing from 28 percent in 1998 to 46 percent of total natural gas production in 2007 (Navigant, 2008). It has been estimated that there are 2,247 trillion cubic feet of gas reserves in the U.S., which is a 118-year supply at 2007 demand levels (Navigant, 2008).

Figure 9. Shale Gas basins in the United States.
Map from U.S. Energy Information Administration
http://www.eia.doe.gov/oil_gas/rpd/shale_gas.pdf. Updated May 28, 2009.

Currently, shale gas production is occurring primarily in four fields in the Southwest (Barnett, Woodford, Fayetteville, and Haynesville formations in Texas, Oklahoma, Arkansas, and Louisiana, respectively) and one field in the Northeast (Marcellus, located primarily in New York, Pennsylvania, and West Virginia). In 2008, the gas industry continued to achieve substantial production from these shale formations, leading to a large increase in EIA's estimate of the unproven shale gas resource base to 267 Tcf (EIA, 2009a). The Potential Gas Committee (the PGC consists of volunteer experts who are associated with a wide variety of natural gas industry, governmental, and academic institutions and share a common interest in the Nation's future natural gas supply) reported in 2009 that estimated natural gas resources rose by 35 percent from 2006 to 2008 (PGC, 2009). The current estimated natural gas resource, which includes proven reserves, is largely attributed to shale formations and the ability of advanced drilling and hydraulic fracturing to recover gas. This large increase in reserves arose from reassessments of active and newly developed shale gas plays in the Appalachian basin of the Atlantic area, the Arkoma and Fort Worth basins of the Midcontinent area, several basins of the Gulf Coast area, and the Uinta basin of the Rocky Mountain area.

In the U.S., numerous shale gas basins exist with a resource potential of many hundreds to thousands of Tcf. To date, only a small number of basins have achieved commercial success. In addition to the Marcellus Shale and other shale units in the Appalachian Basin, significant gas shale gas production occurs in the Barnett Shale in the Fort Worth Basin, Lewis Shale in the San Juan Basin, Antrim Shale in the Michigan Basin, Woodford in Oklahoma, Fayetteville in Arkansas, and New Albany Shale in the Illinois Basin (Table 23). In Canada, commercial production has not yet been achieved. To date, potential shale gas plays have been identified in the following regions: Horn River Basin in British Columbia, Montney and Doig in British Columbia, Colorado Group in Alberta and Saskatchewan, and Utica Shale in Quebec.

Some studies suggest that shale gas wells have very steep initial decline rates (Figure 10). Although shale gas wells have a rapid initial decline, a low rate of production is expected to be sustained for decades as old wells provide a solid base of production for 40-50 years (Oil and Gas Investor, 2006).

5.1 Other Selected US Shale Gas Areas

One of the first recognized major shale gas plays, the **Barnett Shale** in the Fort Worth basin of North Central Texas, is by far the most active shale gas play in the United States (Figure 9). The play encompasses approximately 5,000 square miles in north central Texas. The Barnett Shale of Texas was under investigation as early as 1981, but not until 1995 were the hydraulic fracturing and horizontal drilling technologies available to successfully produce gas at commercial rates. Today two percent of all the gas consumed daily in the U.S. is produced from the Barnett Shale (Haliburton, 2008). It is estimated that production activity in the Barnett Shale may well continue for another 20 to 30 years. The reservoir ranges from 100 ft to more than 1,000 ft in gross thickness and holds from 50 bcf (billion cubic feet) to 200 bcf of gas per square mile.

Producers applied similar approaches to the relatively new **Woodford Shale** in Oklahoma (Figure 9). Due to its immense development and number of large-scale players, there is an abundance of data on the Barnett shale play; however, less is known about the Woodford and estimates of its potential are still being evaluated. The Woodford play is more faulted (often crossing several faults in a single wellbore) making it easy to drill out of the interval. 3-D seismic and geosteering techniques, in combination with logging "deployed-while-drilling" tools, are important components to successful wells. High silica rocks define the best zones for fracturing, although the Woodford is deeper and has higher fracture gradients than the Barnett. Some producers have obtained promising initial results and the Woodford Shale should continue to expand production.

The **Fayetteville Shale** is an unconventional play within the Arkoma Basin that covers a large area in northwestern Arkansas (Figure 9). Compared to other shale plays throughout the U.S., the Fayetteville Shale is still an early stage play (commercial production started in 2004) with unique challenges. Productive wells penetrate the Fayetteville at depths between a few hundred to 7,000 feet. This is somewhat shallower than the Barnett. Mediocre production from vertical wells prior to 2007 stalled development in the vertically fractured Fayetteville, and only introduction of long lateral horizontal drilling and

hydraulic fracturing has increased initial production rates and drilling activity. At present there is less oilfield infrastructure in place in the area of the Fayetteville, compared to other major plays. 3-D seismic and geosteering are required to ensure that longer laterals of 3,000 or more feet and fracture stages occur in the productive zone. As with most shale gas plays, the growing numbers of wells, need for new infrastructure, and the desire to minimize surface impacts is resulting in an increase in multi-well pad drilling in the Fayetteville Shale.

The **Haynesville Shale** is a recent addition to the U.S. Shale play. It is roughly located between northern Louisiana, East Texas, and southwestern Arkansas. Its potential upside is its geographical proximity to areas of significant expertise and substantial resources in a play that is thought to be many times larger than the Barnett and with higher gas-in-place. The Haynesville is nearing commercial scale with very promising initial production rates. On the downside, the heterogeneous characteristics of the shale (highly laminated with significant lithologic changes over a

few inches) may result in more rapid decline rates than the Barnett or other plays. In addition, at depths of 10,500 to 13,500 feet, this play is deeper than typical shale gas targets, thus increasing costs and technical challenges. Bottomhole temperatures can be 300° F, and wellhead treating pressures can exceed 10,000 psi (Halliburton, 2008). The high-pressure gradient (0.7-0.9 psi/ft) which distinguishes the Haynesville from other shale plays may also result in high decline rates.

Located in the Michigan Basin, the mature **Antrim Shale**, like the Barnett, has been actively exploited for years and has produced 2.6 Tcf through 2007. Over 9,000 predominately vertical wells have been drilled to relatively shallow depths (500 to 2,000 feet) across a 12 county area of Michigan (Goodman and Maness, 2008). The gas in the Antrim has a significant CO_2 content (as high as 30 percent in some wells) and wells require de-watering, thus increasing operating costs.

Located in parts of Illinois, Indiana, and Kentucky, the **New Albany Shale**, has a long history of gas production, but remains in an exploratory stage with
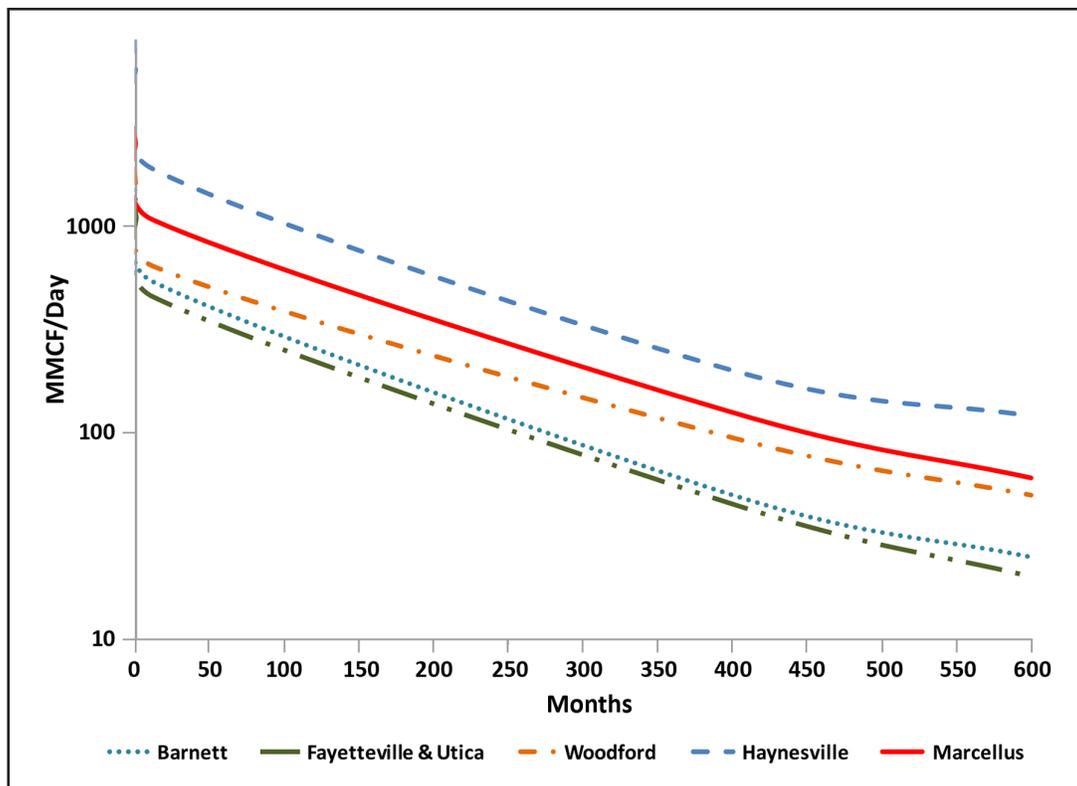
Figure 10. Typical shale gas production decline curves showing rapid initial decline rate followed by multiple decades of low rate production.
Adapted and modified from Jarvie, 2009.

gas production occurring primarily in western Indiana and southwest Kentucky. At less than 4,000 feet, the New Albany is much shallower than the Barnett Shale and requires de-watering similar to the Antrim Shale in the Michigan basin. Limited oil field and pipeline transportation infrastructure have hindered development.

Besides the Marcellus Shale, **other Devonian age shale** units are known under different names, each with slightly different geographical boundaries (e.g., Huron, Chattanooga) within the Appalachian basin. The most productive region lies loosely between Kentucky, Virginia, and West Virginia. While estimated reserves are very large, there are operational challenges. Some of the challenges include small operators and service companies with limited resources, a greater interest in coal mining activities, and the extent of the play which tends to be too dispersed. While limited resources hinder development, low transportation costs and proximity to the highly populated East Coast market are attractive aspects of this play.

Table 3. Identified Shale Gas Areas in the United States.
Data from various published and unpublished sources.

Gas Shale Basin	Marcellus	Antrim	Barnett	Fayetteville	Haynesville	New Albany	Woodford
Estimated Basin Area (mi^2)	95,000		5,000	9,000	9,000		11,000
Depth (ft)	4,000-8,500	400-2,000	6,500-8,500	1,000-7,000	10,500-13,500	500-5,000	6,000-11,000
Net Thickness (ft)	50-250	70-120	100-600	20-200	200	100-350	120-220
Total Organic Content (%)	3-12	5.27	4.5	4.0-9.8		7.06	1-14
Total Porosity (%)			4-5	2-8			
Gas Content (scf/ton)		40-100	300-350	60-220		40-80	
Well Spacing (acres/well)	40-160	30-160	60-160		40-560	80	640
Gas-In-Place (tcf)	1,500		327	52	717	86-160	52
Reserves (tcf)	262-500		44	41.6	251	1.9-19.2	11.4
Estimated Gas Production (10^{3}cf/day/well)	3,100	20-550	338	530	625-1800	275	415

6.0 Infrastructure Concerns

Pipelines are a mature technology and the most economic method for transporting large quantities of CO_2 over long distances. Gaseous CO_2 is typically compressed to a pressure near 2,200 psi (15.2 MPa) in order to increase its density and avoid two-phase flow regimes, thereby making it possible to pump it as a supercritical fluid and easier and less costly to transport than natural gas. CO_2 can also be transported as a liquid in ships, tank trucks, or in rail tankers within insulated tanks. The first CO_2 pipeline built in the United States is the 225 kilometer Canyon Reef Carriers Pipeline (in West Texas), which began service in 1972 for enhanced oil recovery (EOR) in regional oil fields. Other large CO_2 pipelines constructed since then (mostly in the Western United States) have expanded the CO_2 pipeline network for EOR. These pipelines carry CO_2 from naturally occurring underground reservoirs, natural gas processing facilities, ammonia manufacturing plants, and a large coal gasification project (in North Dakota) to oil fields. Altogether, approximately 5,800 kilometers (3,600 miles) of CO_2 pipelines operate today in the United States (Figure 11).
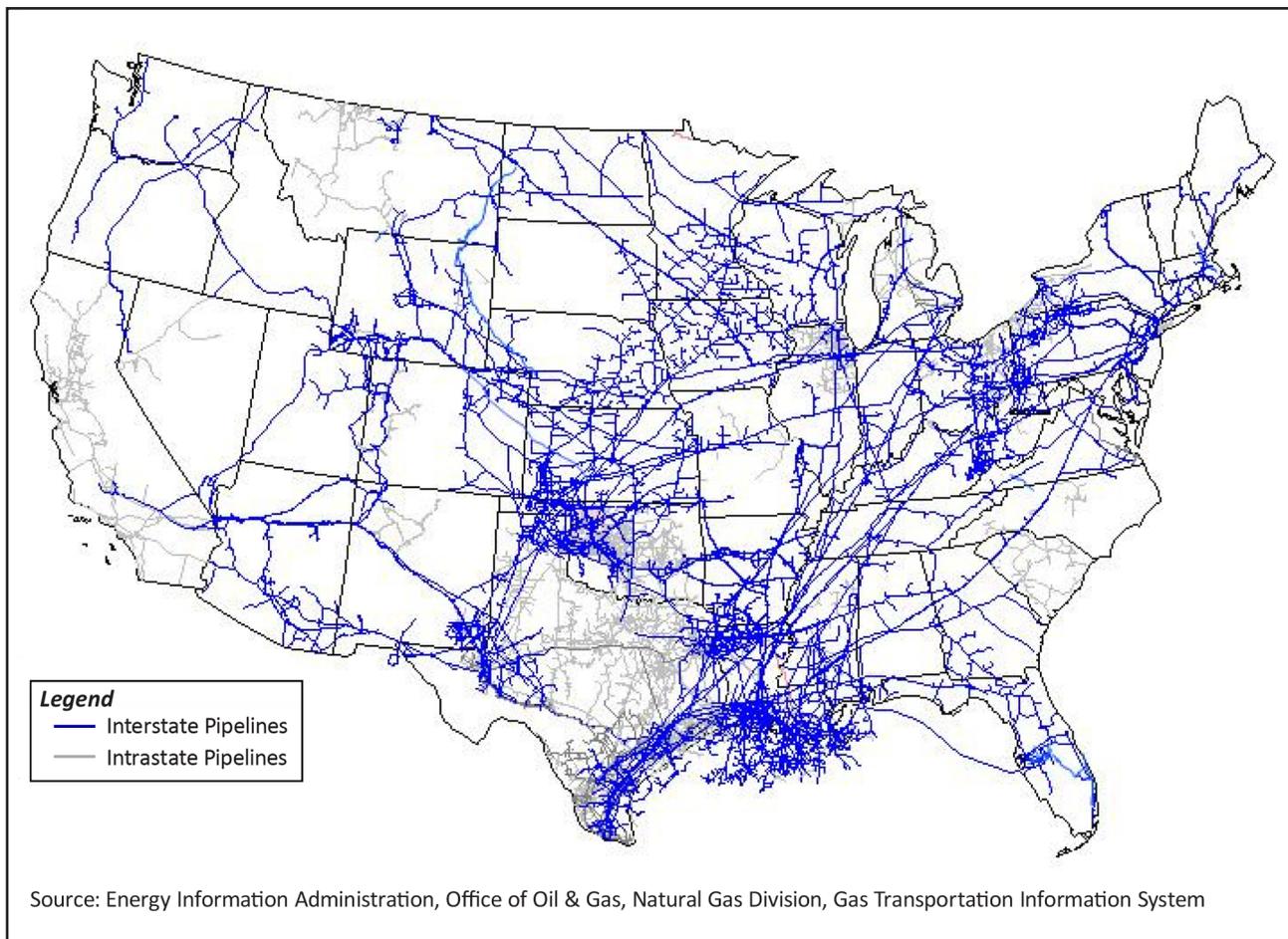
The North American natural gas pipeline network is frequently mentioned as a model for what future CO_2 pipeline networks might look like, since it interconnects natural gas producing basins with thousands of natural gas distribution companies, power plants, and industrial facilities. The technology, scope, operations, commercial structure, and regulatory framework that characterize natural gas pipelines appear to be useful analogues for a CO_2 pipeline system. Overall, the interstate natural gas pipeline grid consists of approximately 217,000 miles of pipeline with a capacity of about 183 Bcf per day (Figure 11) (EIA, 2009). Between 1998 and 2007, natural gas production in the most rapidly expanding production areas of the Nation (northeast Texas, Wyoming, Colorado, Pennsylvania, West Virginia, and Utah (Figure 13) increased by 129 percent, while proven natural gas reserves grew by 188 percent (EIA 2008; EIA 1999). This increase in production and reserves had a significant impact on the increased number of projects and their location (Figures 11 and 12).
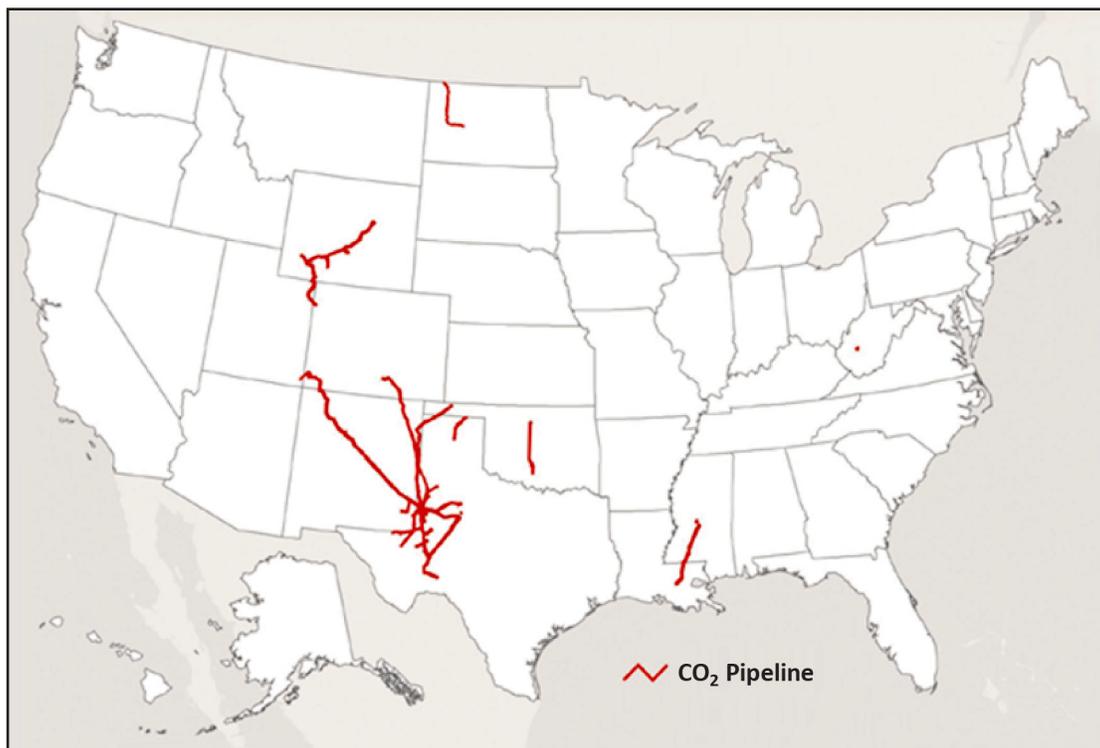
Figure 11. Existing and proposed CO_2 pipelines developed from NatCarb data. (Natcarb is an interactive database developed to show sources of CO_2 and potential sinks for CO_2 storage.)

The design of a CO_2 pipeline is similar to that of a natural gas pipeline except that higher pressures must be accommodated, often with thicker pipe. CO_2 pipelines also differ in that they require CO_2-resistant elastomers around valves and other fittings, and their construction includes fracture arrestors every 1,000 feet to reduce fracture propagation, which is more likely in CO_2 pipelines due to their slower decompression characteristics. Another important difference between a CO_2 pipeline and a natural gas pipeline is that the CO_2 pipeline is moving a supercritical fluid that is pumped, not compressed, at booster stations. This is typically done with centrifugal pumps. Inlet pressures at the pumps would be about 1,850 psi (12.8 MPa) and outlet pressures 2,200 psi (15.2 MPa).

In Pennsylvania and West Virginia the development of the Marcellus Shale is spurring the construction of additional natural gas pipeline infrastructure in the region, particularly large-scale expansions of existing pipelines. Much of the region's existing pipeline grid was built to transport gas flows from the Gulf of Mexico. The Marcellus Shale encompasses more than 95,500 square miles and contains significant undeveloped resources, necessitating a reorientation of the region's existing pipeline grid, as well as new gathering pipelines. For example, El Paso Corporation's Tennessee Gas Pipeline Company plans to construct approximately 125 miles of 30-inch pipeline and add approximately 46,000 horsepower of compression facilities in its existing pipeline corridor in Pennsylvania to transport growing Appalachian production to

Legend
— Interstate Pipelines
— Intrastate Pipelines

Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Figure 12. Major recent expansion projects of the U.S. natural gas pipeline network.
Image from EIA, 2009b.
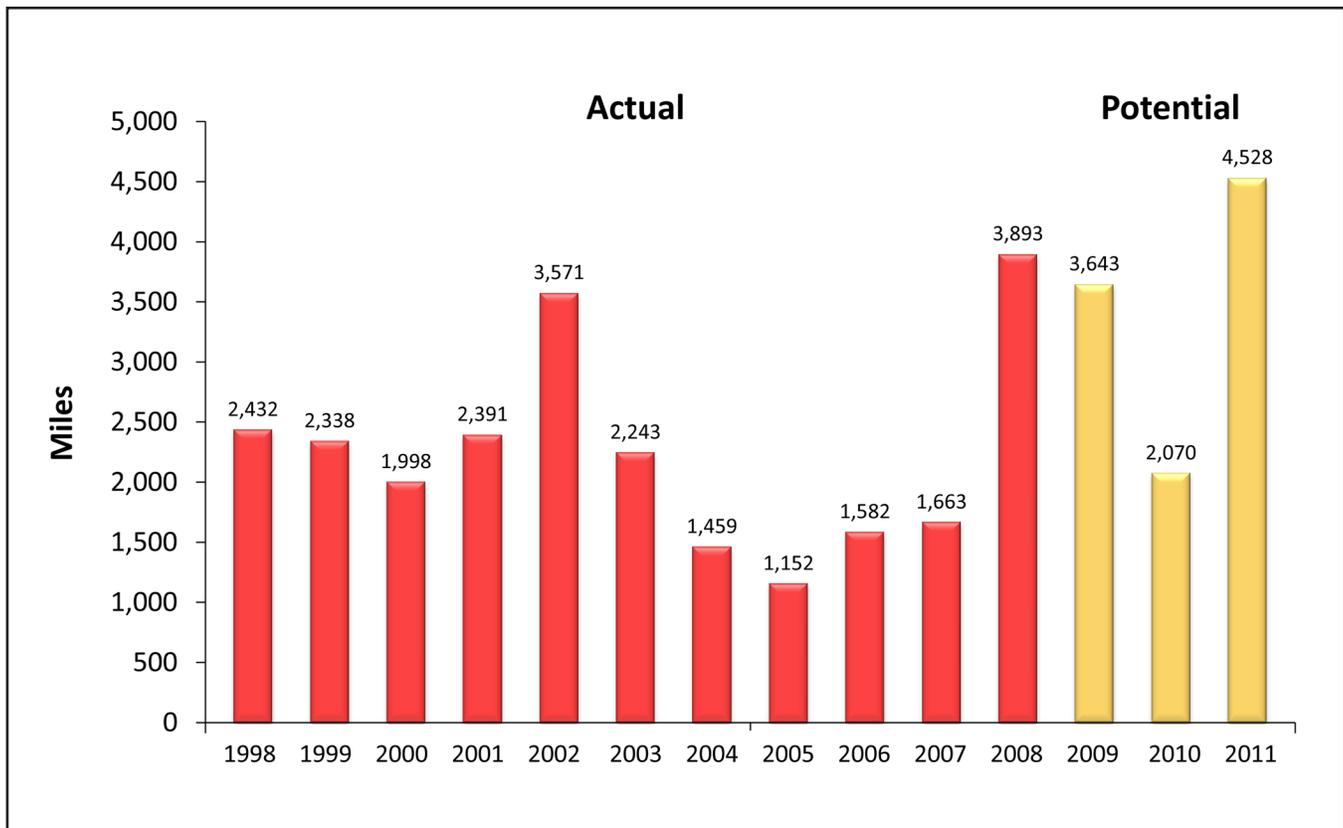
Figure 13. Additions to natural gas pipeline mileage from 1998 to 2011.
Image from EIA, 2009b.

Northeast markets. The project will add capacity of 200 million cf per day (EIA, 2009b).

Existing CO_2 pipeline systems are largely confined to the Southwest U.S. or to relatively short, dedicated pipelines between CO_2 sources (e.g., ammonia manufacturing plants and gas processing facilities) and nearby CO_2 injection sites (Figure 11). In order to develop a significant CO_2 transportation network on the scale of the existing natural gas pipeline infrastructure, it should be recognized that the investment will require significant capital and may entail competition for the same rights-of-way, material, and manpower resources as that of the natural gas and oil pipelines.

7.0 Conclusion and Recommendations

The Marcellus Shale is an extensive formation underlying significant portions of New York, Ohio, Pennsylvania, and West Virginia. As such, it is natural to consider it as a potential sink for CO_2 storage. There are three possibilities for this: (1) storage in the Marcellus Shale itself, (2) storage in formations below the Marcellus, with the Marcellus serving as caprock, and (3) simultaneous gas production and CO_2 storage, similar to enhanced coalbed methane (ECBM) recovery in coal. Because of the very low permeability of the Marcellus Shale, the first of these options is possible only in conjunction with gas production where the formation has been hydraulically fractured to create increased porosity where the CO_2 could be stored. The potential for this option is limited for several reasons: (1) Marcellus Shale wells tend to produce over long periods of time, so it could be a long time before wells may be available and (2) the fracturing process could create fissures which could allow CO_2 to potentially migrate out of the Marcellus. However, low permeability formations above the Marcellus would serve as caprocks to prevent upward movement of CO_2.

The second option of storing CO_2 in formations below the Marcellus may have potential, but a major concern is that the hydraulic fracturing used to recover gas may render the Marcellus unsuitable as a caprock by allowing stored CO_2 to migrate upward through the formation. However, the additional shale sequences above the Marcellus should impede the upward migration of CO_2. Data are needed to evaluate this CO_2 storage option.

The third option entails combined CO_2 storage/methane production similar to CO_2 injection into coal seams, where injected CO_2 adsorbs on organic surfaces and displaces methane. However, no data are currently available to evaluate this option. Furthermore, this option might result in too high a CO_2 content in the natural gas.

The potential for using abandoned gas pipelines for CO_2 transport needs further study because of the different pressure levels, pumping requirements, and corrosion effects of CO_2 compared to methane. Some old gas wells may be useable for CO_2 injection if the cements used can resist CO_2.

As gas production from the Marcellus Shale has increased, this may present an opportunity for CCS in the Marcellus, but more data are needed. As discussed above, this presents an opportunity for CCS in the Marcellus, but more data are needed. There is only one study for CH_4/CO_2 adsorption in shale; and this study indicates that five molecules of CO_2 are adsorbed per molecule of CH_4 produced (compared to three to one for a typical coal). However, the rate of CO_2 adsorption in shale is only one tenth that for coal. Much more data must be generated to allow evaluation of this option, such as the effect of CO_2 on the Marcellus Formation rocks, how much methane can be displaced by CO_2, and adsorption isotherms for methane and CO_2. After the necessary data are generated and further analyzed, it is likely that some option for CO_2 storage can be further analyzed and potentially developed.

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