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A Critical Evaluation of Unconventional Gas Recovery from the Marcellus Shale, Northeastern United States

Dae Sung Lee*, Jonathan D. Herman, Derek Elsworth***, Hyun Tae Kim****, and Hyun Suk Lee*******

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Abstract

The Marcellus tight gas shale represents a significant resource within the northeastern United States. It is both a large reserve, with an estimated 30 to 300 TCF of recoverable gas, and is close to some of the largest prospective markets in the country. However, production is fraught with technological obstacles, the most significant of which include prospecting, access by drilling, stimulation, and recovery. Prospecting is difficult because viability of the reservoir relies both on the original gas in place and in the ability to access that gas through pre-existing fractures that may be developed through stimulation. Drilling is a challenge since drilling costs typically comprise 50% of the cost of the wells and access to the reservoir is improved with horizontal drilling which may access a longer productive zone within the reservoir than cheaper vertical wells. Finally, stimulation methods are necessary to improve gas yields and to reduce the environmental impacts of both consumptive water use and the subsequent problems of safe disposal of fracwater waste. We discuss the challenges involved in the economic recovery of gas from tight gas shales in general and the Marcellus in particular.

Keywords: *Marcellus shale, tight gas, hydraulic fracturing, horizontal drilling*

1. Introduction

The Marcellus gas shale underlies 140,000 km^2 of the Appalachian Basin beneath the northeastern states of West Virginia, Pennsylvania, Ohio and New York at an approximate average depth of two kilometers, Fig. 1. The thickness of the formation averages 30 meters, but thicknesses as high as 75 meters have been measured in northeastern Pennsylvania. This "super giant" gas field (Myers, 2008) contains an estimated 295-2,700 TCF[1] of natural gas in place and recoverable reserves on the order of 10% of this amount – these approximate between one and ten years supply at the current annual rate of US consumption (21 TCF/year). The richest portions are in north-central Pennsylvania and south-central New York. Despite the size of this reserve, significant technological challenges remain in the economic recovery of gas from this distributed unconventional reservoir. These include accurately prospecting the richest reserves, rapidly accessing the deep reservoir by drilling and in effectively stimulating the low porosity and low permeability formation.

Shale porosities and permeabilities are low. Matrix porosities are in the range 0.5%-5.0% (Myers, 2008) and bulk permeabilities are in the micro- to nano-Darcy range. Fracture porosity, a crucial characteristic for gas recovery, ranges from 2.0% to 7.0% in the Marcellus. Joint sets are oriented east-northeast and dictate optimum azimuths of horizontal wells towards the north-northwest. The gas is currently harvested by either vertical or horizontal drilling, usually accompanied by hydraulic fracturing to increase the permeability of the shale. Hydraulic fracture stimulation uses a mixture of slickwater and proppant to increase the permeability of the formation by an average of one to seven orders of magnitude. It has been estimated that horizontal wells

[1]We use standard oilfield terminology: TCF=trillion cubic feet; BCF =billion cubic feet; MCF=thousand cubic feet; MCFD=thousand cubic feet per day; M=thousand; MM=million.

*Senior Researcher, Petroleum & Marine Research Department, Korea Institute of Geoscience & Mineral Resources, Daejeon 305-350, Korea (E-mail: leeds@kigam.re.kr)

**Graduate Student, Department of Civil and Environmental Engineering, Pennsylvania State University, University Park, PA 16802 (E-mail: jdh33@psu.edu)

***Professor, Dept. of Energy and Mineral Engineering, Pennsylvania State University, University Park, PA 16802, USA (E-mail: elsoworth@psu.edu)

****Principal Researcher, Petroleum & Marine Research Department, Korea Institute of Geoscience & Mineral Resources, Daejeon 305-350, Korea (E-mail: htkim@kigam.re.kr)

*****Researcher, Petroleum & Marine Research Department, Korea Institute of Geoscience & Mineral Resources, Daejeon 305-350, Korea (Corresponding Author, E-mail: hyun0922@kigam.re.kr)

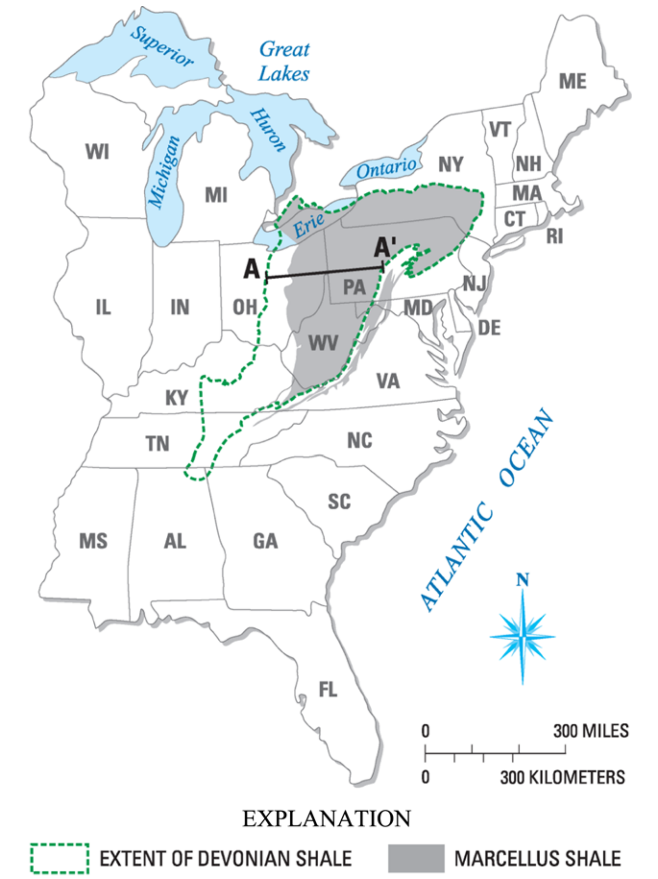

Fig. 1. Distribution of the Marcellus Shale (Modified from Milici *et al.*, 2006)

in the Marcellus will yield an Estimated Ultimate Recovery (EUR) of 4 Billion Cubic Feet (BCF) of gas (Engelder *el al.*, 2008). The production curve follows an exponential decay and normally drops to one-fifth of initial production within five years, produces at this rate for the next twenty to thirty years. Overworking of wells with acid or CO_2 may be effective in restoring production to initial post-stimulation magnitudes, and at relatively low cost (Engelder *el al.*, 2007 & 2008).

Environmental considerations accompanying Marcellus gas production include surface land disturbance and water withdrawals. Water consumption for horizontal wells may be of the order of 2-4 million gallons with 90% consumed during stimulation. Continued development of the field is expected to drive consumptive water use from current levels of 6 million gallons/day to 19 million gallons/day by 2013. The largest environmental concern, however, is the disposal of hydraulic fracturing fluids which typically contains high concentrations of dissolved solids from the formation. In rank order of increasing cost these are either re-injected, treated for reuse as drilling fluids or brought to drinking water standards.

Despite this yield, significant uncertainties exist within recovery of gas from these tight reservoirs. Challenges include effective methods of drilling, completions and stimulation to recover an increased fraction of the resource and at a rapid rate. In the following, we document these challenges and focus on potential solutions.

2. Petroleum System

The Marcellus shale is black organic-rich shale found in the Appalachian Basin of the northeastern United States. The Marcellus formed during the Devonian Period (approximately 390 Ma) as the product of sedimentation caused by the Acadian orogeny. This shale was deposited deep-water and anoxic environment, preserving its organic content; this organic matter eventually transformed into natural gas, which remains trapped in the fractures, pore spaces and organic matter of the shale

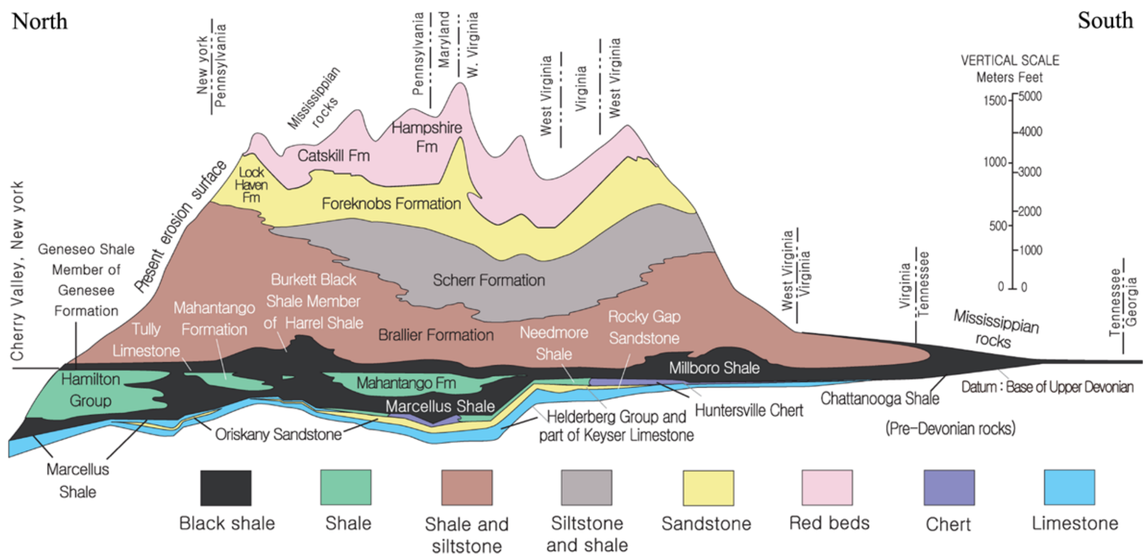

Fig. 2. The Cross-section of Marcellus Shale (Milici *et al.*, 2006)

(Barrett, 2007). Unlike conventional hydrocarbon resources, which occur in discrete traps, the Marcellus gas spans a large geographic area and is therefore classified as an unconventional, or continuous, resource (Milici *et al*., 2006). The depth and low permeability of the Marcellus formation previously made gas production unprofitable, but recent increases in the price of gas and improvements in harvesting technology such as horizontal drilling have sparked renewed interest in the Marcellus shale (Harper, 2008).

2.1 Geology

The Marcellus Formation occupies a geographic area of approximately 140,000 km^2 in the Appalachian Basin. Figure 2 shows the distribution of the Marcellus shale, along with a cross-section showing the surrounding formations. In general, both the depth and thickness of the Marcellus increase toward the east (Milici *et al*., 2006), as shown in Fig. 3. Thicker shale will likely contain more natural gas, but deeper formations will increase drilling costs. A maximum thickness of approximately 60 meters occurs in northeast Pennsylvania; a minimum depth of less than 0.9 km occurs in eastern Ohio.

2.2 Reservoir Characteristics

2.2.1 Porosity

Porosity estimates of the shale matrix are in the range 0.5–5.0% (Myers, 2008) with outlier magnitudes of 9.0% recorded in West Virginia (Soeder, 1988). However, the matrix pore spaces in Marcellus are poorly connected; the successful extraction of natural gas therefore depends largely on the fracture porosity of the shale.

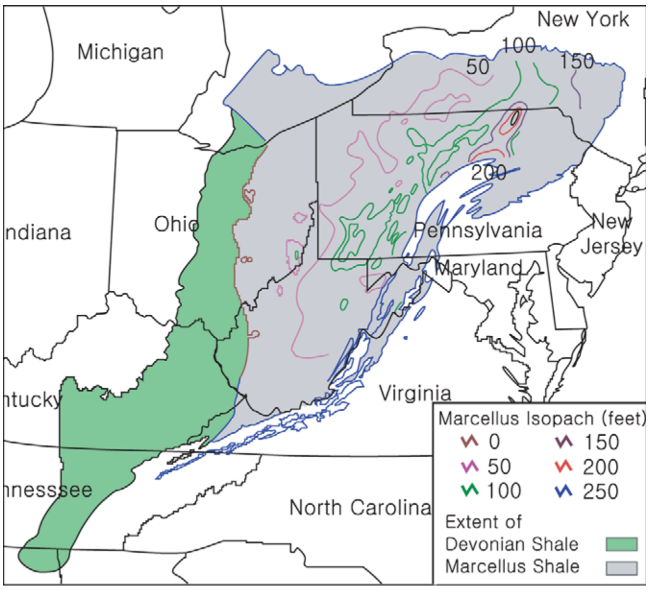

Fig. 3. Thickness of the Marcellus Formation, in Feet (Milici *et al*., 2006)

2.2.2 Fracture Porosity

There are two primary joint sets (J_1 and J_2) in Devonian shales in the Appalachian Basin. J_1 trends east-northeast and parallels the direction of maximum horizontal stress; J_2 trends northwest (Engelder *et al*., 2007). Both joint sets were created hydraulically: when the Marcellus entered the gas window approximately 290 Ma, the newly created methane increased pore pressure, fracturing the shale incrementally (Engelder *et al*., 2008). For natural gas extraction, the joints J_1 should be targeted for two reasons. First, J_1 runs parallel to the direction of maximum horizontal stress, making it more permeable than J_2. Second, J_1 is better developed in the Marcellus and is also more closely spaced, which allows more gas to be harvested from a single well (Engelder *et al*., 2007).

2.2.3 Permeability

Permeability estimates fall between 10^{-21} and 10^{-17} m^2 for the Marcellus shale (Myers, 2008), with an outlier measurement of 10^{-14} m^2 in a West Virginia core sample (Soeder, 1988). In general, the permeability of the Marcellus is very low and must be increased artificially to extract gas. The Marcellus has such low permeability that it is considered a hydrocarbon seal, along with the underlying Onondaga limestone (Milici *et al*., 2006).

2.2.4 Saturation

The gas in the Marcellus contains water that must be removed for pipeline transport. The water content of Marcellus gas has been estimated at 1,100 mg H_2O/m^3 gas. Typical pipeline specifications require that the gas contain only between 64 - 112 mg H_2O/m^3 gas; this excess water must be removed prior to transport (Agbaji *et al*., 2009).

2.3 Gas-In-Place Estimates

Several estimates of the amount of gas contained in the Marcellus (total discovered and undiscovered resource) have been published. Table 1 compares these estimates. This gas within the Marcellus is either contained in pore spaces, contained in fractures, or adsorbed to minerals and organics (Agbaji *et al*., 2009); because of its low permeability, the shale serves as the petroleum source, seal, and reservoir (Arthur *et al*., 2009). Typically 10% of the gas-in-place is considered to be recoverable. The amount of recoverable gas-in-place has been estimated to be as low as 1.9 TCF (Milici *et al*., 2006), but this will likely increase to 10% of the gas in-place estimates with improvements in harvesting technology. For comparison, the United States

Table 1. Comparison of Marcellus Gas-in-place Estimates, in TCF

Publication	Gas-in-Place Estimate (TCF)
Charpentier, 1993 (USGS) (Milici, 2006)	295
Engelder & Lash, 2008	500
Tristone Capital, Inc., 2008	2700
Navigant Consulting, 2008	1500

consumed approximately 21 TCF of natural gas in 2006 (Sumi, 2008). A gas reservoir with more than 30 TCF of recoverable gas can be considered a "super giant" field (Myers, 2008), and with the estimates given in Table 1, the Marcellus appears to fit this classification.

3. Harvesting the Resource

3.1 Current Methods

3.1.1 Prospecting

Geophysical prospecting in gas shales involves determining the stratigraphy, brittleness, porosity, and fracture pattern of the formation. Stratigraphy is commonly found using gamma-ray logs, since the Marcellus has a much higher radioactive signature than the surrounding formations. This allows prospectors to determine the local depth and thickness of the Marcellus. Brittleness is an important characteristic for predicting the local response to fracture stimulation; brittle sections of the Marcellus will likely fracture more easily, allowing greater gas recovery. For example, in the Barnett shale, the most brittle sections were found to be those rich in silica and low in clay. These compositions are generally found by core analysis (Jacobi *et al*., 2008). Brittleness can be determined from the Young's Modulus, Poisson's Ratio, and Brinell hardness of the shale, all of which are determined from core samples (Kundert *et al*., 2009). Porosity and permeability are determined by core analysis or in-situ nuclear magnetic resonance. Other porosity measurements, such as acoustic and neutron-density methods, are affected by variations in composition and organic content of the reservoir rock and are therefore less accurate (Jacobi *et al*., 2008). Fracture orientation and density can be determined using Logging-While-Drilling (LWD) imaging; this allows rapid decisions to be made regarding the direction of drilling and the potential efficacy of fracture stimulation (Quinn *et al*., 2008). Any commercially viable play must have either existing fractures or planes of weakness (Walser, 2007).

Seismic techniques may also be used at the beginning of the prospecting stage to determine the stratigraphy of the subsurface. Reflected waves reveal stratigraphic boundaries and anticipated gas contents may be correlated between tracked layers from their initial sampling point. Microseismic techniques are occasionally used during hydraulic fracturing to determine the effectiveness of the treatment by mapping the newly created fracture network (Ottaviani, 2009).

3.1.2 Drilling

Gas wells in the Marcellus can be drilled either vertically or horizontally, as shown in Fig. 4. Vertical wells are cheaper to drill, but only intersect a limited amount of the Marcellus shale reservoir at depth. Horizontal wells are able to intersect a greater length of Marcellus, draining a greater area of natural gas while minimizing surface impact (Kundert *et al*., 2009). The length of these lateral sections ranges from two to five thousand feet

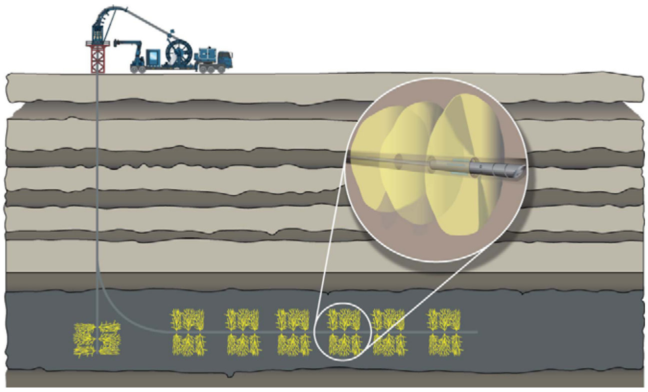

Fig. 4. Horizontal Drilling and Hydraulic Fracturing

(Beauduy, 2009). Horizontal wells cost more, however, approximately \$3.5 million (USD) compared to \$1 million for a vertical well (Agbaji *et al*., 2009). In some areas, the natural fractures of the Marcellus run vertically, in which case horizontal drilling is necessary to intersect the existing fracture network (Engelder *et al*., 2008). It is desirable to drill horizontal wells perpendicular to the natural fractures in order to intersect as many fractures as possible. Since the primary joint set (J_1) trends east-northeast, horizontal wells should be drilled to the north-northwest. At the surface, the borehole may be as wide as 20 inches to accommodate casings, but the lower sections of the well are typically drilled with a 9-inch diameter and filled with a 5.5-inch production casing (Ottaviani, 2009; Janwadkar, 2009).

Traditional rotary steerable drilling systems encounter several problems when attempting directional drilling in deep gas shales, including slide drilling, difficulty controlling trajectory, and low Rate of Penetration (ROP). A new Rotary steerable Closed-Loop System (RCLS) improves on these problems by employing three hydraulically powered steering ribs on a non-rotating sleeve; the ribs steer the drill bit by exerting forces on the borehole walls, Fig. 5. The RCLS system improves ROP over traditional systems from roughly 16 ft/hr to over 20 ft/hr (Janwadkar, 2009).

This system increases ROP and reduces drilling costs compared to the traditional rotary systems. It is capable of turning up to 10º

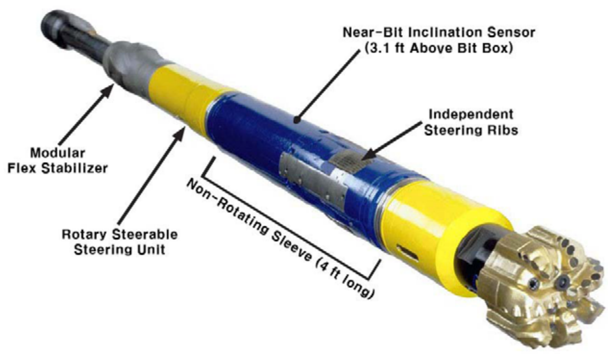

Fig. 5. Rotary Closed-Loop System (RCLS) Bottom-Hole Assembly (Baker Hughes)

for every 100 feet of depth. The RCLS has been proven effective in the Woodford shale of Oklahoma. The drill bit pictured in Fig. 5 -and that most commonly used in shale drilling- is the Polycrystalline Diamond Compact (PDC) bit, which is chosen for its superior durability in hard formations. Finally, the drilling fluid used for Marcellus shale is generally water-based mud, with additives such as barite to increase the density of the fluid (Agvaji *et al*., 2009).

3.1.3 Completion

Once drilled, the well must be cased and perforated before gas production can begin. Four layers of casing are typically required. They are, in order of increasing depth: conductor casing, which contains the surface soil; surface casing, which isolates the local aquifers from drilling fluids; intermediate casing, which isolates the gas flow from shallower gas and oil reservoirs; and production casing, which transports gas to the surface. All layers of casing are sealed with cement sheaths (Ottaviani, 2009). The bottom of the production casing must then be perforated using controlled charges to allow gas to flow from the shale to the pipe. Perforations should be focused on the most brittle areas of the formation, with, on average, three perforations per foot over two-foot intervals. The holes should be about 0.4 inches in diameter (Kundert *et al*., 2009). Following perforation, gas can flow from the shale to the wellhead. Initially, gas production may spike as the gas trapped in large fractures travels to the surface, but stimulation is normally required to access the gas trapped in the pore spaces of the shale (Bell *et al*., 2009).

3.1.4 Stimulation

The most common method of well stimulation is hydraulic fracturing as illustrated in Fig. 6. Hydraulic fracturing involves the injection of pressurized water or gas into the well, which creates new fractures in the shale and enlarges existing ones. The objectives of hydraulic fracturing are to increase fracture density in the formation and decrease fracture spacing (Ozkan *et al*., 2009). The newly created fractures tend to parallel the direction of maximum horizontal stress (Arthur *et al*., 2009). Therefore, if a horizontal well were drilled perpendicular to the joints J_1 in the Marcellus, an hydraulic fracture stimulation would generate

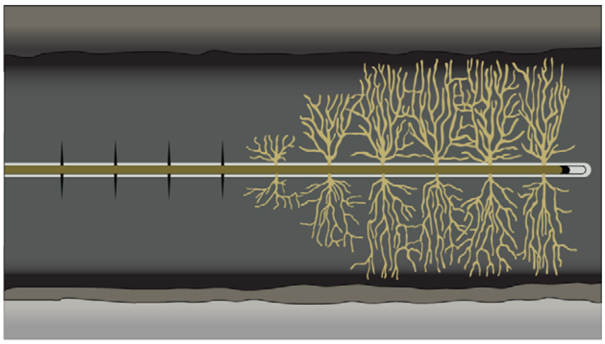

Fig. 6. Hydraulic Fracturing using Proppant in a Horizontal Well

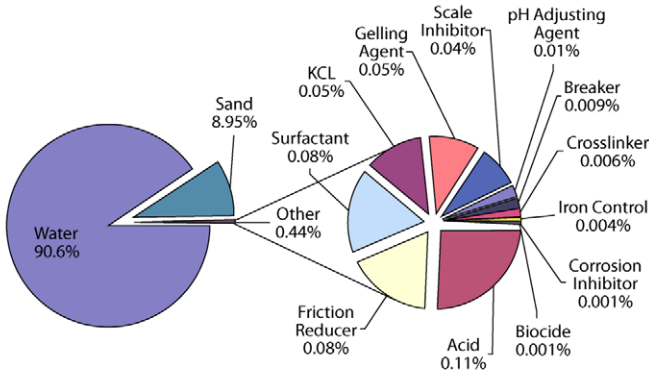

Fig. 7. Composition of Hydraulic Fracturing Fluid used in the Fayetteville Shale (Arthur *et al*., 2009)

transverse fractures parallel to J_1, maximizing the potential for gas recovery. Additionally, the drilling crew must take care not to fracture formations around the Marcellus. These accidental fractures can disrupt water flow and recovery; however, they are typically prevented in the Marcellus by the Onondaga limestone, which underlies the Marcellus and acts as a fracture barrier (Engelder, 2009). The typical hydraulic fracturing fluid for shale is slickwater, a mixture of water, sand, and lubricants, in which the sand serves to prop open the newly formed fractures in the rock. Figure 7 shows the typical composition of hydraulic fracture fluid in the Fayetteville shale.

The primary components of the fluid are water and proppant, which is often sand but can also includes resins or ceramics. Resins are used near the end of the stimulation process to hold proppant in place; ceramics are used when a stronger proppant is required. Ceramics also have a lower specific gravity than sand, allowing them to remain buoyant in the slickwater (Kaufman *et al*., 2008). Gels are used to increase the viscosity of the water, allowing it to carry proppant more effectively, but these are not recommended for brittle shale stimulation. Acid (typically 15% HCl) is used to remove cement from the perforations. When acid is used, a corrosion inhibitor protects steel casings. Similarly, biocides prevent bacteria from growing in the wellbore. Potassium Chloride (KCl) stabilizes clay in the formation against swelling. Finally, breakers (often peroxydisulfates) are added during injection to reduce gel viscosity and release proppant into the fractures (Arthur *et al*., 2009). Companies rarely disclose the exact compositions of their fracturing fluids, but they are increasingly required to do so in order to comply with environmental regulations (Swistock, 2009).

The hydraulic fracture stimulation is usually completed in stages, especially in horizontal wells, where a tremendous pressure would be required to fracture the entire lateral at once. Instead, the lateral is separated into intervals of approximately 500 feet, and these are then fractured individually. Within each of these stages, components of the fracture mixture are added separately. First, the wellbore is flushed with freshwater, then flushed with acid to clean the perforations. The well is sealed and pressurized

Table 2. Planned Proppant Schedule for Marcellus Well Stimulation (Personal communications)

Stage	Proppant (lb/gal)	Total Volume (gal)	Stage (continued)	Proppant (lb/gal)	Total Volume (gal)
Lubricant Pad	--	100,000	Sweep	--	5,000
80/100 Mesh Sand	0.50	80,000	30/50 Mesh Sand	2.00	50,000
Sweep	--	5,000	Sweep	--	5,000
80/100 Mesh Sand	0.75	80,000	30/50 Mesh Sand	2.50	50,000
Sweep	--	5,000	Sweep	--	5,000
30/50 Mesh Sand	1.00	50,000	20/40 Mesh Sand	2.50	25,000
Sweep	--	5,000	Sweep	--	5,000
30/50 Mesh Sand	1.50	50,000	20/40 Mesh Sand	3.00	25,000

to force the water and acid to fracture the formation. Lubricants are then added to facilitate the insertion of proppant. Proppant is usually added in several stages of increasing grain size and concentration. For example, 100 mesh sand may be used initially at a concentration of 0.1 pounds per gallon (ppg), followed by 40/70 mesh sand at 0.3 ppg. Once the fractures are propped, the well is again flushed with freshwater to remove excess proppant, and the well begins producing gas (Arthur *et al*., 2009).

A case study of fracture stimulation in a vertical Marcellus well in southwest Pennsylvania has recently been reported. The stimulation used a total of 545,000 gallons of water, composed of 0.5% slickwater additives. The design called for a pumping rate of 50 Barrels per Minute (BPM), although this was not achieved in practice due to very high friction near the perforations. The fluid was pumped with a pressure of approximately 6,000 psi throughout the treatment, which was higher than expected. Table 2 shows the schedule for the entire stimulation was planned for 50 BPM. This design requires a total of 100,000 lb of 80/100 mesh sand, 350,000 lb of 30/50 mesh sand, and 137,500 lb of 20/40 mesh sand. The intermediate sweeps contain no proppant and are intended to remove sand accumulation in the wellbore. This schedule was designed for a vertical well; horizontal wells typically use between four and eight times more water. Hydraulic fracture stimulation in gas shales typically increases fracture conductivity to between 0.5 and 10 md-ft, which represents an overall increase in formation permeability between 1 and 7 orders of magnitude, depending on the width of the fractures; larger permeability values lead to greater gas recovery (Warpinski *et al*., 2008).

3.1.5 Production

After stimulation, gas begins to flow from the shale to the wellhead. Generally, the gas is sufficiently pressurized to flow to the surface without any additional pumping (Ozkan *et al*., 2009). Producing wells are normally measured in terms of their production rate and Estimated Ultimate Recovery (EUR); results will vary based on the type, size, and location of wells. EUR data from the Barnett shale shows the expected relationship between vertical and horizontal well productions. The EUR values in Table 3 do not apply directly to the Marcellus, but the relationship between horizontal and vertical productions should.

Table 3. Estimated Ultimate Recovery (EUR) Per well in the Barnett Shale (Valko, 2009)

Barnett Shale Gas Production				
	Vertical Wells		Horizontal Wells	
Year	# Wells	Mean EUR Per Well	# Wells	Mean EUR Per Well
2004	452	0.438 BCF	402	1.44 BCF
2005	256	0.369 BCF	787	1.27 BCF
2006	189	0.589 BCF	1353	1.37 BCF
2007	107	0.488 BCF	2363	1.28 BCF

Horizontal wells in the Barnett are consistently producing about three times more gas than vertical wells, and as a result, vertical wells are being phased out. This type of detailed production history is not yet available for the Marcellus, but it has been estimated that Marcellus wells will yield an average EUR of 4 BCF per well (Engelder, 2009).

Once the well is constructed, production is expected to decay with time in proportion to the current production. This relationship has been expressed in the following model (Valko, 2009):

$$q = q_0 \exp\left[-\left(\frac{t}{\tau}\right)^n\right] \tag{1}$$

where q is the production rate (gas per time), t is time since construction, n is a model parameter, and τ is the characteristic time constant. Cumulative production is then found by integrating $q(t)$ from $t = 0$ to the current t; estimated ultimate recovery (EUR) is similarly found by integrating $q(t)$ from $t = 0$ to $t = \infty$. It has been estimated that Marcellus production decays to one-fifth of the initial flow rate after five years, and continues to produce at that rate up to twenty years (Agbaji *et al*., 2009). The model in Eq. (1) was fit to these conditions (Fig. 8) using an estimated initial flow rate of 5 million CFD, which gave the parameters $n = 0.1$ and $\tau = 0.1\ \text{yr}^{-1}$.

The initial rate of 5 million CFD was estimated from current initial flow rates reported in the Marcellus. Production will gradually fade out after about twenty years; in this example, the producer could expect to recover roughly 7.8 BCF from the well

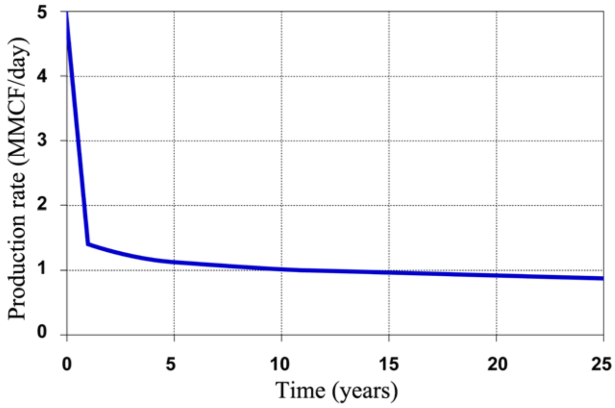

Fig. 8. Marcellus Production Decline Curve (Approximate)

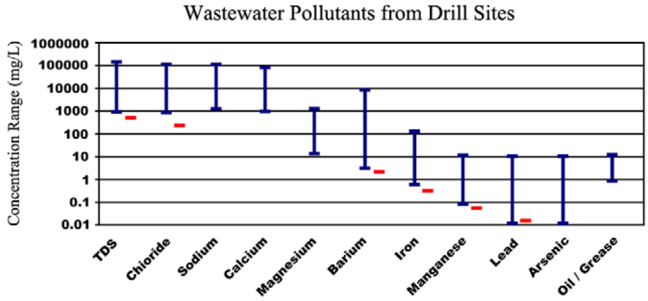

Fig. 9. Range of Contaminant Measurements in Twenty Samples of Marcellus Wastewater (Swistock, 2009)

over its lifetime, which falls in the upper range of the estimated Marcellus shale EUR and far above the Barnett shale EUR values in Table 3.

However, many wells will not continue to produce for twenty years and may need to be reworked or re-fractured to improve production. Reworking a well typically involves flooding it with CO_2 or a microemulsion treatment. CO_2 preferentially sorbs to organic matter in the Marcellus, which mobilizes natural gas and sequesters CO_2 simultaneously. CO_2 should be injected into the well only after maximum gas production has been achieved, thereby extracting the most total gas from the well while also sequestering the desired amount of CO_2 (Jikich, 2003). Microemulsions can be applied to increase permeability and enhance gas recovery, but the success of these treatments depends heavily on the chemical composition of the emulsion (Zelenev, 2009).

3.2 Environmental Considerations

3.2.1 Drilling Site

Preparation of the drilling site requires movement of heavy equipment on often inadequate rural roads; this creates the potential for erosion and contamination of small streams and watersheds (Soeder *et al.*, 2009). Furthermore, the construction of roads and well pads requires significant land disturbance, although this can be reduced by drilling horizontal wells. Land disturbance may also affect nearby wildlife populations. Within the well itself, a casing and cement layer are required to separate the local aquifer from the well bore. Corrosion and leaks in this casing pose only minor long-term threats, since they are relatively unlikely to occur.

3.2.2 Water Use and Disposal

Between drilling and hydraulic fracturing, the construction of a horizontal well typically requires between 2 and 4 million gallons of water. The total water use in the Marcellus is projected to increase from the current 6.1 million Gallons per Day (GPD) to 18.7 million gpd by 2013, with 95% of this water consumed by fracture stimulation. Most of the demand (60-70%) will be met with surface water withdrawals (Gaudlip *et al.*, 2008). This water requirement poses more problems in other areas of the United States than it does in the Appalachian Basin. It is estimated that during peak Marcellus production in Pennsylvania, the requisite water use will only constitute about one percent of the state's daily consumption (Ottaviani, 2009). However, water use can still cause environmental problems locally if withdrawals are too concentrated or occur under drought conditions.

The larger environmental concern involved in Marcellus drilling is wastewater disposal. Between 30-70% of the hydrofrac water returns to the surface; the rest of the wastewater comes from the formation itself. The chemicals added to the hydrofrac water are a concern, but the most concentrated contaminants are the Total Dissolved Solids (TDS) and metals from the Marcellus. Figure 9 shows the range of contaminants in drilling wastewater from twenty samples in Pennsylvania, with the Environmental Protection Agency (EPA) standards (EPA Limits) for each marked in red, if any exist.

Several options exist for disposing of this wastewater. First, the wastewater can be treated to EPA drinking water standards and discharged into the environment. This treatment must remove almost all of the contamination and is therefore very expensive. The second option is to inject the wastewater deep into the ground, where confining layers will prevent it from ever contaminating an aquifer (Soeder *et al.*, 2009). Finally, the wastewater can be treated for reuse in the drilling process. This involves far less treatment and is currently being researched by several companies (Gaudlip *et al.*, 2008). In general, more treatment facilities must be constructed to accommodate wastewater from gas drilling, because municipal water treatment plants are not equipped for this purpose.

4. Current Production

Over the past three years, Marcellus wells in Pennsylvania produced a daily average of 84 thousand cubic feet (MCF) of gas each (Harper, 2009). Figure 10 compares the Marcellus production values to the production of other Pennsylvania formations; the three columns for each formation represent the three years during which production was measured. The Marcellus has not been the most productive formation thus far, but it has provided

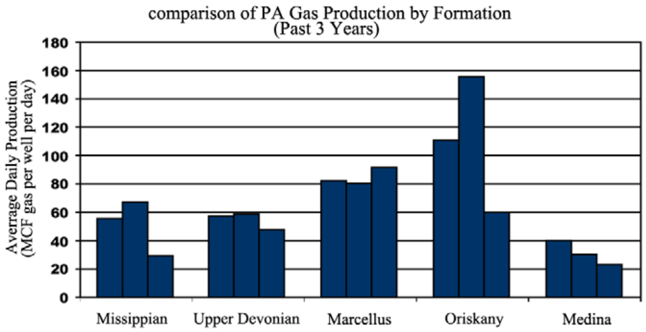

Fig. 10 Comparison of Per-well Production from Pennsylvania (PA) Gas Formations (Personal Communications)

stable production; some estimate that the Marcellus can produce at this rate for up to twenty years. The data given in Fig. 10 do not specify the number of wells involved or the production rates for individual companies. Operating primarily in western Pennsylvania and eastern Ohio, an operator was producing a total of 60 million CFD from its eighty wells as of October 2008.

One of the large producers of Marcellus gas in the Appalachian Basin operates primarily in western Pennsylvania and eastern Ohio. The company was producing a total of 60 million CFD from its eighty wells as of October 2008. On a per-well basis, this production is much higher than the average rate of 84 thousand CFD discussed above. The company hopes to operate a total of 150 wells – most of them vertical – and to increase total production to 250 million CFD by the end of 2009. At this point, the company will evaluate whether horizontal wells produce enough gas to justify the additional cost.

5. Conclusions

In the Marcellus Basin of Pennsylvania alone, the estimated reserve of 3,800 Tcf is enough to supply current gas consumption in the US for 180 years. However, despite the substantial size of this reserve, significant challenges exist in effectively and economically recovering the gas. These challenges relate first to locating and assessing the resource, accessing it effectively through drilling and stimulation and producing the gas for as complete a recovery as is possible. Stimulation is the principal issue influencing the economic viability of gas production from the Marcellus and hydraulic fracturing costs typically account for the remaining 50% of well costs. Improved methods of stimulation are necessary to improve gas yields and to reduce the environmental impacts of both consumptive water use and the subsequent problems of safe disposal of fracwater waste. CO_2 is used as a workover fluid for well rehabilitation and could also be applied as a hydraulic fracturing fluid as the well is first stimulated. These necessary innovations suggest the need for a sustained and focused program of research applicable to tight gas shale reservoirs in general, and focused on the Marcellus in particular.

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