

Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program



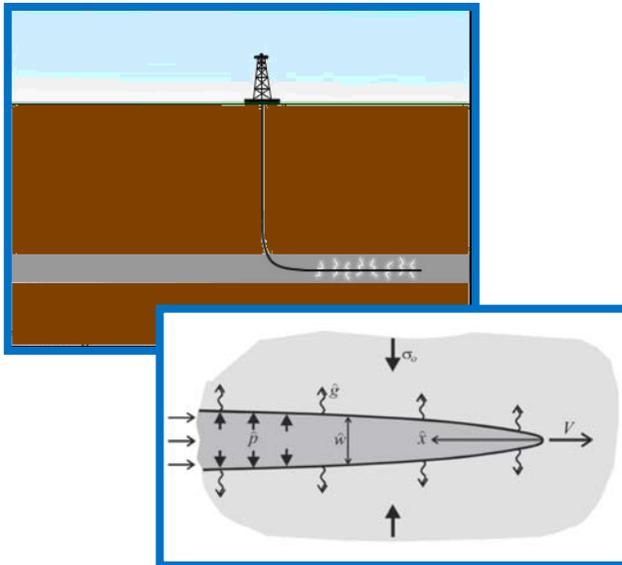
Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs

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INTRODUCTION: TASK 1 - TECHNICAL ANALYSIS OF HYDRAULIC FRACTURING

The New York State Department of Conservation (DEC) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus Shale for natural gas production and expects to receive applications to drill in other areas including counties where natural gas production has not previously occurred. Well development in unconventional gas formations such as the low permeability shale formations in New York will probably require a stimulation process known as hydraulic fracturing.

DEC evaluated the environmental impacts of oil and gas drilling and published the results in the report *Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program* in July 1992. The Department has determined that the issuance of permits for wells developed using horizontal drilling and high-volume hydraulic fracturing requires additional analysis under the State Environmental Quality Review Act (SEQRA). DEC will publish the results of this analysis in a draft Supplemental Generic Environmental Impact Statement (dSGEIS) for public review and comment. The dSGEIS will evaluate issues related to horizontal drilling and high-volume fracturing beyond the review presented in the GEIS.

The specific objectives of Task 1 include

- researching the current state-of-practice for hydraulic fracture design,
- researching the subsurface mobility of fracturing fluids and additives,
- preparing a narrative discussion of the hydraulic fracturing state-of-practice,
- preparing a narrative discussion of the fracturing fluid mobility, and
- evaluating regulatory mechanisms for notification, application, review and approval of high volume hydraulic re-fracturing operations.

New York State environmental quality review regulations require identification of potential significant adverse environmental impacts that can be reasonably anticipated. This document presents information to help in the evaluation of the significance of any such impacts.

SUBTASK 1.1: SUMMARY OF HYDRAULIC FRACTURING DESIGN

The hydraulic fracturing process uses hydraulic pressure to overcome the in situ compressive stresses in the target geologic formation, creating tensile stresses in the rock sufficiently high to open existing or create new joints. The fracturing (or “frac”) fluid typically contains solid particles, or proppants, suspended in and transported by the frac fluid that hold the fractures open upon the release of the fluid pressure. The propped-open joint provides a pathway with higher hydraulic conductivity to convey the formation fluid or gas from the formation matrix to the wellbore.

Well developers have devised many variations on this basic hydraulic fracturing process which remains a combination of both quantitative analysis and qualitative judgment. The optimum process to stimulate a particular well with respect to fracture length and productivity depends on the geometry of the well, the characteristics of the geologic formation, the cost of stimulation, and the market price for gas. Well developers may vary the type of frac fluid used, the additives in that fluid, the proppant, the volumes of fluid and proppant, the applied pressure, the duration of pressure application, the areas targeted for stimulation, and the pre-frac and post-frac well cleanup procedures. Hydraulic fracturing may take place immediately upon well completion, at some time after initial production, or multiple subsequent times after the initial hydraulic fracturing (refracking). Each hydraulic fracturing operation may include one or more stages, with each stage involving a specific target zone, fluid composition and volume, and proppant type and volume.

A hydraulic fracturing stage comprises multiple steps, each of which involves the injection of fluid which may contain additives and suspended solids. A hydraulic fracture stimulation stage may begin with an acid treatment to clean up the well itself and the immediately adjacent area by removing residue from drilling muds and helping to restore the formation permeability. The next step, the pad, fills the wellbore with fracturing fluid and, by increasing the fluid pressure, opens fractures in the formation. In subsequent steps, fluid containing a low concentration of proppant begins to fill the open fractures. The initial proppant steps typically use fine proppant that the frac fluid can carry the maximum distance into the fractures. Later proppant steps may increase the proppant concentration or the proppant particle size. After all of the proppant steps, flushing with clean water removes excess proppant in the wellbore. Some fracturing fluids leave a residue which reduces the fracture permeability and which requires further cleanup.¹

Hydraulic fracturing methods continue to evolve as well developers encounter new geologic situations, experiment with different techniques, and incorporate new technologies. The list below shows the dates of some important innovations, and illustrates the rapid pace of changes in recent years. As new unconventional shale gas plays come into production, one can expect additional innovations in the future.

¹ Arthur, J.D., et al, 2008. “Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale,” Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

Hydraulic Fracturing Technological Milestones ²	
Early 1900's	Natural gas extracted from shale wells. Vertical wells fracked with foam.
1983:	First gas well drilled in Barnett Shale in Texas
1980-1990s	Cross-linked gel frac fluids developed and used in vertical wells
1991	First horizontal well drilled in Barnett Shale
1991	Orientation of induced fractures identified
1996	Slickwater fracturing fluids introduced
1996	Microseismic post-fracturing mapping developed
1998	Slickwater refracturing of originally gel-fracked wells
2002	Multi-stage slickwater fracturing of horizontal wells
2003	First hydraulic fracturing of Marcellus shale ³
2005	Increased emphasis on improving the recovery factor
2007	Use of multi-well pads and cluster drilling

Much of the experience in fracturing tight gas shales comes from the Barnett Shale gas play. Current practice generally relies on slickwater fracs, i.e. the injection of a fracturing fluid consisting of about 98% to 99.5% fresh water mixed with a friction reducer and other additives.⁴ Sand is most commonly added as the proppant. Slickwater fracs typically require millions of gallons of water, and many wells are refractured several times during their producing life.⁵ Typical designs for horizontal well stimulations include two to eight stages of stimulation, two to four fracture zones per stage, two to four foot long perforated sections of well pipe per fracture zone with six shots (holes) per foot spaced radially at 60 degrees. During the treatment, fracture fluid pumping rates reach 840 to 1,260 gal/min, with about 1,800 gallons used per foot of well fractured.⁶

1.1.1 Pre-frac simulation and modeling

Fracture propagation models attempt to mathematically describe the hydraulic fracturing process. Given a set of input parameters such as the geologic properties of the formation, the material properties of the frac fluid and proppant, and the injection volumes and rates, the models predict details of the fracture development such as fracture position, fracture dimensions, proppant placement, post-frac reservoir permeability, reservoir pressure, and gas recovery rates.

Fracture models have evolved over the past fifty years as the physical processes have become better understood and as computational techniques and power have improved. Early models developed during the 1960's and 1970's primarily incorporated analytical techniques to estimate the dimensions of fractures with simple geometries. Two-dimensional numerical models focusing on fracture propagation and proppant transport appeared in the 1970's, with three-dimensional numerical models appearing the following decade. These early numerical models generally treated the rock mass as a homogeneous linear elastic material, considered leakoff⁷ of

² Matthews, H. Lee, "Overview of Shale Gas Stimulation Techniques." Search and Discovery Article #40335, Adapted from oral presentation at AAPG Annual Convention, April 20-23, 2008, San Antonio, Texas.

³ Harper, John A., "The Marcellus Shale - An Old "New" Gas Reservoir in Pennsylvania," *Pennsylvania Geography*, Spring 2008, Vol. 38, No. 1.

⁴ DOE, Office of Fossil Energy, 2009. *Modern Shale Gas Development in the United States: A Primer*, prepared under DE-FG26-04NT15455.

⁵ Railroad Commission of Texas, 2008. "Water Use in the Barnett Shale," URL: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php, accessed July 30, 2008.

⁶ Halliburton, 2008. "Trends in Unconventional Gas," Articles from *Oil and Gas Journal*, 2007-2008.

⁷ Leakoff is the loss of fracturing fluid into the pore matrix of the rock.

a single fluid phase, and did not consider responses in the reservoir behavior due to the stress changes imposed by the hydraulic fracturing. Advances in the understanding of the underlying physics led to model enhancements in the 1980's and 1990's related to proppant transport, acid transport, reservoir flow, and high leakoff scenarios. The best current models consider more fully-coupled interactions between the fracturing process and reservoir geomechanical properties and can handle multiphase flow, non-uniform stress distributions, proppant transport, capillary effects, permeability plugging, non-Darcy flow, and reservoir production.^{8,9}

Current research efforts include improved 3-D gridded finite element and finite difference models with fully coupled geomechanical and fluid flow properties.¹⁰ Some researchers have also reported success with neural network models¹¹ and genetic algorithms¹² to optimize frac treatments without detailed reservoir characterization, but this method relies on past well design data, past hydraulic fracturing design information, and production history for other wells in the same formation.¹³

Typical input parameters for current simulation models include properties of the fracturing fluid (density, viscosity, wetting characteristics), amount of fracturing fluid, properties of the proppant (particle size, density), amount of proppant, characteristics of the target formation (thickness, stress state, tensile strength, Young's modulus, Poisson's ratio, existing fracture pattern, reservoir pore pressure, permeability, saturation, porosity, temperature, leakoff rates, and fracture closure pressure), and characteristics of the bounding strata (tensile strength, stress-strain characteristics).^{14,15,16}

Properly characterizing the in situ conditions requires the use of appropriate techniques to measure key in situ parameters such as the Young's modulus and the state of stress. Investigators can determine Young's modulus from rock cores, but because so many in situ parameters influence the modulus, geophysical velocity measurements produce more reliable values. Some researchers assert that only direct measurements of in situ stresses such as from closure tests and microfracs produce reliable stress values, and dismiss the trustworthiness of stress measurements from dipole sonic logs. Other in situ parameters such as formation permeability, porosity, and leakoff rates can vary due to anisotropy and formation heterogeneity, making accurate measurements difficult.^{17,18}

⁸ Settari, A, 2009. "Review of Fracturing Modeling Technology," Presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, January 19-21, 2009.

⁹ Malpani, R.V., December 2006. *Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

¹⁰ Flesher, Robert, 2009. "Stimulation in Tight Gas Sands," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

¹¹ Neural networks are non-linear statistical data modeling tools that try to simulate physical processes using a system that adapts to information during a learning phase. They can be used to model complex relationships or to find patterns in data.

¹² Genetic algorithms are iterative search methods that use evolutionary techniques to optimize solutions to mathematical problems.

¹³ Mohaghegh, S., Balan, B., Ameri, S., West and McVey, D.S, 1996. "A Hybrid, Neuro-Genetic Approach to Hydraulic Fracture Treatment Design and Optimization," Presented at the SPE Annual Technical Conference & Exhibition, October 6-9, 1996, Denver, Colorado, Report No. SPE 36602.

¹⁴ Malpani, R.V., December 2006. *Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

¹⁵ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

¹⁶ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

¹⁷ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

¹⁸ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

Measurements taken in the wellbore prior to fracturing the formation can provide useful information on some model parameters. Measurement and analysis of the decline in pre-frac injection pressure can yield the system permeability, for example. Field tests such as Perforation Inflow Diagnostic (PID) analysis and closed chamber testing can help determine initial reservoir pressure and in-situ permeability. Reservoir pressure is required for both the design of hydraulic fracturing stimulations and for the later evaluation of reservoir production. Drilling service companies use optimization software in conjunction with pressure injection sequences to determine the in-situ rock stress and fracture closure pressure to design and to evaluate fracture treatments.^{19,20,21}

Expected outputs from the models include fracture spacing, fracture half-length²², and width. The optimum half-length and width depend in part on the post-cleanup fracture permeability and the formation matrix permeability.²³ Hydraulically induced fractures often grow asymmetrically and change directions due to variations in material properties. In formations with existing natural fractures, such as the Barnett and Marcellus shales, hydraulic fracturing can create complex fracture zones as fracturing pressure reopens existing fractures and as induced fractures and existing fractures intersect. Actual fracture patterns are generally more complex than the current conceptual models predict.^{24,25,26,27}

1.1.2 Fracture monitoring

To supplement the modeling predictions, to improve understanding of the effects of varying frac procedures, and to confirm fracturing outcomes, several techniques have been developed which allow mapping of the actual fractures induced by hydraulic fracturing. Fracture mapping helps to confirm that fracture growth is sufficient for production and to confirm that induced fractures are limited to the target formation. Frac monitoring also helps to improve the efficiency and to monitor the cost effectiveness of the fracturing process.

Tiltmeters measure angular changes that occur during hydraulic fracturing with a precision as small as 1 arc second, and can be placed either at the ground surface or in nearby boreholes. As the depth to the target formation increases, surface measurements become less useful and the cost of drilling nearby monitoring boreholes increases. Since hydraulic fracturing opens up the rock mass, the process creates an increase in volume in the fractured area. The bulge created by the perhaps less than 1% volumetric increase distorts the geologic materials above and around the fracture zone. Arrays of tiltmeters measure the distortion, and the data is used to deduce the shape, location, and magnitude of the affected zone. The magnitude of the

¹⁹ Barree, R. D., 2009. "Hydraulic Fracture Stimulation in Tight-Gas Reservoirs." January 19, 2009.

²⁰ Hawkes, R., 2007. "Pre-frac Reservoir Characterization from Perforation Inflow Diagnostic (PID) Testing - Measure Twice -Frac Once," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Series.

²¹ Schlumberger, 2003, *Services*, "DataFRAC Service."

²² Since fractures tend to be symmetrical with respect to the wellbore, the fracture half-length is defined as the distance from the wellbore to the fracture tip.

²³ Hawkes, R., 2007. "Pre-frac Reservoir Characterization from Perforation Inflow Diagnostic (PID) Testing - Measure Twice -Frac Once," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Series.

²⁴ Maxwell, S.C., T.I. Urbancic, N. Steinsberger, Devon, and R. Zinno, "Fracs tracked using microseismic images," *E&P*, August 2003, p. 58-59.

²⁵ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

²⁶ Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, June 2006.

²⁷ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

increase can be used to estimate the total fracture space created, but can not yield the width of individual fractures unless the fracture spacing is also known.^{28,29}

Microseismic mapping relies on arrays of highly sensitive tri-axial accelerometers in offset wells to detect the pressure or shear waves that result from shearing and cracking of the rock mass during fracturing. By measuring the time of arrival of individual signals at multiple sensors, the source of each microseismic event can be calculated in three dimensions. Microseismic mapping can identify the location, length, height, direction, and internal structure of fractures but does not provide any information on fracture width.^{30,31,32}

Chemical and radioactive tracers added to the frac fluids or proppant have been used to help map the induced fracture network. Chemical tracers generally require additional offset wells to detect the trace chemical. Radioactive tracers can be detected with wireline gamma-logging equipment in the wellbore, but their use poses additional environmental and safety concerns. The effectiveness of stimulation treatments has also been mapped with distributed temperature surveys performed along the wellbore or in offset wells. The surveys identify areas in which the intrusion of frac fluid causes temperature changes.^{33,34,35}

A recently developed method for fracture mapping involves the use of a proppant with a special resin coating containing a tagging material. After the proppant is pumped into the fractures, a downhole fast neutron source activates the proppant tag, which then emits characteristic gamma rays. A downhole gamma ray spectrometer detects the emitted radioactivity. The intensity of the signal provides information on the fracture location and the amount of proppant in the fracture. The half life of the material in the proppant tag is so short that radioactivity has decayed before the logging tool is even retrieved from the well.³⁶

Fracture monitoring can provide valuable information on the effectiveness of well stimulation. These techniques are not regularly used in production wells due to their cost, but are more often used to evaluate new techniques, the effectiveness of fracturing in newly developed areas, or to calibrate hydraulic fracturing models. Most wells are evaluated based on the pressure and flow conditions during injection and during production.³⁷

1.1.3 Post-frac and production well testing

To improve the understanding of the results of hydraulic fracturing, pre-frac simulation and modeling is supplemented with post-fracture and production measurements. This integrated approach can lead to better comprehension of the reservoir characteristics, the fracture pattern,

²⁸ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

²⁹ U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

³⁰ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

³¹ Schlumberger, 2006. "Improve Production with Optimum Fracture Design in Real Time." October 2006.

³² U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

³³ Hexion, S.V. "Fracturing Technology: Improving technology for fracture height," *E&P Magazine*, September 2008.

³⁴ Bybee, Karen, 2009. "Technology Focus: Hydraulic Fracturing," *Journal of Petroleum Technology*, Society of Petroleum Engineers, March 2009.

³⁵ Reynolds, Rodney R., "Produced Water and Associated Issues," Oklahoma Geological Survey, Open-File Report 6-2003. 2003.

³⁶ Hexion, S.V. "Fracturing Technology: Improving technology for fracture height," *E&P Magazine*, September 2008.

³⁷ Bybee, Karen, 2009. "Technology Focus: Hydraulic Fracturing," *Journal of Petroleum Technology*, Society of Petroleum Engineers, March 2009.

and future gas production. The most common techniques involve measuring the gas bottomhole pressure (BHP) or flow rates over time.

Pressure Transient Analysis (PTA) involves the measurement of the gas pressure in a well as the flow rate varies. Although there are many variations on the test procedures, the most common tests are pressure buildup or falloff tests that, respectively, end or start at a well shut-in condition. The solution method to derive the reservoir properties depends on the specific form of the PTA test, but the common outputs are formation permeability, formation pressure, fracture half-length, fracture conductivity, leakoff rates, and effective reservoir area or volume. In addition to predicting the future performance of a well, PTA testing can also help identify productivity problems in a well.³⁸

PTAs should be run after cleanup of the drilling or frac fluids, otherwise early post-fracture PTAs may yield misleading results such as overestimation of formation permeability, underestimation of fracture length, and overestimation of the future production rate. Today, readily available software packages perform the analyses and can handle complications such as near-wellbore damage, skin effects, and non-Darcy flow.³⁹

During production, longer term pressure and flow records can provide information on the reservoir characteristics and the long term gas recovery potential. A variety of analytical techniques are in use, but the underlying principle of all the methods is history matching, i.e. matching the actual production against past performance of similar wells or theoretical models to forecast the long term performance.⁴⁰ Analysis of the production data can produce estimates of formation gas permeability, fracture half length, fracture conductivity, and drainage area.⁴¹

Production analysis methods currently in use include⁴²:

- Arps decline curve analysis
- Fetkovich decline curve analysis and type curve matching
- Blasingame type curve analysis
- Agarwal-Gardner type curve analysis
- Normalized Pressure Integral (NPI) type curves
- Flowing Material Balance
- Numerical Modeling

Each of the above production analysis methods has its advantages and disadvantages, but none of the methods produces the most reliable solution in every situation. Using a combination of methods can increase the certainty of the analytical result and provide more clarity in explaining the physical responses of the reservoir.^{43,44,45}

³⁸ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

³⁹ Bachman, Bob, 2007. "Resolving Inconsistencies between Well Test and Designed Fracture Lengths," Presented at The Petroleum Society of the CIM Technical Luncheon, November 6, 2007.

⁴⁰ Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, June 2006.

⁴¹ Malpani, R.V., December 2006. *Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

⁴² Al-Reshedan, Faisal, S., Ahamed Gawish, and Hazim N. Dmour, "Evaluation the Methodologies of Analyzing Production and Pressure Data of Hydraulic Fractured Wells in Low Permeability Gas Reservoirs", *Oil and Gas Business*, Ufa, Russia, 13 February 2009.

⁴³ Barree, R. D., 2009. "Hydraulic Fracture Stimulation in Tight-Gas Reservoirs." January 19, 2009.

⁴⁴ Malpani, R.V., December 2006. *Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

Recent advances have been made by researchers to improve the reliability of the pre-frac models by linking or coupling the pre-frac models, fracture mapping, and production data analysis. An important goal of the model developers is the development of a simulation technique for unconventional gas reservoirs which can model the fracture stimulation, evaluate the stimulation results, and predict the potential reservoir production. Current challenges to better understanding of the environmental and production impacts of reservoir stimulation include developing models at an appropriate scale to handle both near-wellbore and distant reservoir effects, to increase the complexity of the models to handle multilayer effects, to extend the research advances to the commercial software packages, and to increase the use of the advanced models by practicing engineers.^{46,47,48,49}

Table 1 summarizes fracture diagnostic techniques and indicates the relative degree of certainty with which each technique can determine the fracture characteristics listed.

Table 1: Comparison of Fracture Diagnostic Techniques⁵⁰

Analysis Technique	Fracture Location	Fracture Height	Fracture Length	Analytical Stage
Tiltmeters	High	Low	Low	During fracture
Microseismic	High	High	High	During fracture
Fracture Modeling	-	Low	Low	Pre-frac or post-frac
Radioactive Tracers	Low	High	-	Post-frac
Temperature Logging	-	Low	-	Post-frac
Well Testing	-	-	Low	Post-frac
Production Data	-	Low	-	Post-frac

1.1.4 Fracturing materials

1.1.4.1 Fluids

A wide variety of base fluids for hydraulic fracturing have been tested and used for gas wells. The choice of fluid is usually made on the basis of the formation characteristics and cost. Some work well in certain geologic formations but not in others, and some have simply lost favor because more promising materials have come along. These base fluids include the following:

- Oil-based fluids, often diesel-based
- Methanol or methanol/water blends
- Polymer linear and crosslinked gels
- Non-polymer viscofied and crosslinked fluids
- Borate and organometallic crosslinked fluids
- Emulsions and foams
- Saline water
- Freshwater

⁴⁵ Al-Reshedan, Faisal, S., Ahamed Gawish, and Hazim N. Dmour, "Evaluation the Methodologies of Analyzing Production and Pressure Data of Hydraulic Fractured Wells in Low Permeability Gas Reservoirs", *Oil and Gas Business*, Ufa, Russia, 13 February 2009.

⁴⁶ Settari, A, 2009. "Review of Fracturing Modeling Technology," Presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, January 19-21, 2009.

⁴⁷ Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, June 2006.

⁴⁸ Bybee, Karen, 2009. "Technology Focus: Hydraulic Fracturing," *Journal of Petroleum Technology*, Society of Petroleum Engineers, March 2009.

⁴⁹ Vera, Sergio Armando Jerez, December 2006. *Using multi-layer models to forecast gas flow rates in tight gas reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

⁵⁰ Geospace Technologies, 2004. "Microseismic hydraulic fracture monitoring," 2004.

Oil-based frac fluids are not frequently used in tight gas shale formations because they have not been found to be as cost-effective as other methods, and have largely been discontinued in coalbed methane wells following a 2003 agreement between the EPA and the three largest hydraulic fracturing specialty contractors Halliburton, Schlumberger, and BJ Services. These three companies perform approximately 95% of the hydraulic fracturing stimulations in the U.S. The agreement only applies to coalbed methane wells in underground sources of drinking water (USDW). Non-aqueous frac fluids of all types account for only 8% of current fracturing operations in North America.^{51,52}

Methanol or methanol/water blends reduce the rate of leakoff, and thus aid in the maintenance of sufficient fracturing pressure and the recovery of fracturing fluid. They are often used with a cellulose-based gelling agent.

Polymer gels provide greater viscosity which helps to keep the proppant in suspension and to carry it deeper into induced fractures. The gel residue, however, requires the use of “breakers” to clean the proppant and recover the pore space between the proppant grains. Residual permeability of the proppant pack due to gel residue after cleanup is typically 2% to 5% of the permeability of the undamaged proppant pack, and recovered permeability as low as 1% is not uncommon.^{53,54} Crosslinked gels based on borate or organometallic compounds can withstand higher temperatures, allow some control over the delay of the crosslinking, provide good proppant transport, and tend to have higher recovered permeability than the polymer gels.⁵⁵

Foamed gels and foamed emulsions use nitrogen gas or liquid carbon dioxide in a water-based fluid to reduce the volume of fracturing liquid that must be injected and recovered. Foamed gels can carry a relatively high proppant load. The gas bubbles in the foam help to pressurize or energize the formation and enhance return flow during frac fluid recovery. Foaming agents can reduce formation damage (plugging) and reduce the amount of cleanup required. As recently as 2003, nitrogen-based foam fracturing was the most common fracturing method in vertical shale wells in the Appalachian Basin.^{56,57,58}

Based on recent experience in the Barnett Shale in Texas and other tight gas shale formations, the most likely fracturing fluid to be used for hydraulic fracturing in the Marcellus and other New York shales is apt to be water, either freshwater or a light brine. Water treatments in the Barnett

⁵¹ Brannon, Harold D., 2009. “Fracturing Materials,” Presented at the SPE Hydraulic Fracturing Technology Conference, January 19-21, 2009, The Woodlands, Texas.

⁵² U.S. EPA, 2003, “Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells”, Memorandum of Agreement Between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation, 12 December 2003.

⁵³ Brannon, Harold D., 2009. “Fracturing Materials,” Presented at the SPE Hydraulic Fracturing Technology Conference, January 19-21, 2009, The Woodlands, Texas.

⁵⁴ Barree, R. D., 2009. “Hydraulic Fracture Stimulation in Tight-Gas Reservoirs.” January 19, 2009.

⁵⁵ Brannon, Harold D., 2009. “Fracturing Materials,” Presented at the SPE Hydraulic Fracturing Technology Conference, January 19-21, 2009, The Woodlands, Texas.

⁵⁶ U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

⁵⁷ Gottschling, J. C., T. N. Royce, and L. Z. Shuck, 1985. “Nitrogen Gas and Sand: A New Technique for Stimulation of Devonian Shale,” *Journal of Petroleum Technology*, May 1985, p. 901-907.

⁵⁸ Hill, David G., Tracy E. Lombardi and John P. Martin, 2003, “Fractured Shale Gas Potential in New York”, New York State Energy Research and Development Authority, Albany, New York, USA.

Shale reportedly have produced better results than gel treatments, especially slickwater fracturing, i.e. the use of water or light brine with a friction reducing additive.⁵⁹

Slickwater fracturing fluids are low cost since the base fluid is water, and have low viscosity which reduces pumping pressures and increases penetration into the formation. They have relatively poor proppant suspension and transport characteristics, however due to the low permeability of tight shale formations, significant stimulation can be achieved with low concentrations of fine sand. In the Barnett, a slickwater frac in a vertical well can use in excess of 1.2 million gallons of water. Horizontal wells often require 3.5 to 5 million gallons, and may be fracked several times during their producing life.^{60,61,62}

Less data is available on proppant and water requirements in the Marcellus Shale in New York, but based on experience in Pennsylvania, one operator predicts that a vertical well would require about 800,000 gallons of water and 250,000 lbs of sand. Stimulation water estimates by others range from 545,000 gallons for a typical vertical well to 2,500,000 gallons of water for a multi-stage horizontal well. Recent applicants for horizontal wells in Delaware County, New York estimate water use at about 500,000 gallons per frac stage.^{63,64,65}

As the pressure is released near the end of a well stimulation, the fracturing fluid reverses flow to the wellbore in a process called flowback. Not all of the fracturing fluid is recovered, and the amount left in the formation depends on the fluid used, the fracture geometry, the reservoir pressure, and the geologic details of the formation. In the Barnett Shale, a typical well returns 20% to 30% of the injected fluid during flowback, with most of this recovered in the first two or three weeks of production. Recovery of frac fluid continues after flowback and into the production phase as additional frac fluid is flushed out of the formation with the produced water. The remainder of the trapped fluid may impede gas withdrawal by filling pore spaces, reducing the fracture permeability, reducing the pore area available for flow, and reducing the effective fracture length. Advances in surfactant technology have led to the use of additives which enhance water recovery. Non-ionic microemulsion alcohol ethoxylates, for example, have reportedly produced improvements in frac fluid recovery and subsequent gas production of 50% to 100%.^{66,67,68}

In addition to recovery of the frac fluid, the well may produce water from the formation. Experience with and expectations for the Marcellus Shale are that produced water volumes will be low.

⁵⁹ Malpani, R.V., December 2006. *Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

⁶⁰ Brannon, Harold D., 2009. "Fracturing Materials," Presented at the SPE Hydraulic Fracturing Technology Conference, January 19-21, 2009, The Woodlands, Texas.

⁶¹ *Fort Worth Basin Oil & Gas Magazine*, "The Future of Water Recycling," Issue No. 14, February 2009.

⁶² Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁶³ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

⁶⁴ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁶⁵ Chesapeake Appalachia LLC, 2009, Application for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Law, various wells, March 2009.

⁶⁶ Heinze, Jim, "Stimulation in Gas Shales," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

⁶⁷ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

⁶⁸ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

1.1.4.2 Proppants

In hydraulic fracturing, proppants are used to hold the created fracture open against the formation stresses after the fracturing pressure is removed. The propped fracture provides a flow path of higher conductivity than the intact rock mass and improves the flow of gas from the geologic formation to the wellbore. Proppants are solid particles that vary in material type, dimension, density, crushing strength, and temperature stability. Selection criteria for proppants include the ability to remain suspended and be transported by the fracturing fluid, the ability to physically fit in the induced fractures, the ability to remain intact under the fracture closure stresses, and the hydraulic conductivity of the proppant-filled fracture.

Proppants generally consist of relatively inert materials. The most common material is sand, but lightweight ceramics, sintered bauxite, and even walnut shells have been used. Small diameter particles and less dense materials have better transport characteristics than heavier, larger particles that settle more quickly. Lightweight proppants generally have lower crushing strengths than denser materials. The specific gravity of proppants ranges from 3.55 for sintered bauxite to 1.08 for ultra-lightweight, neutral density materials. Sand, the most common proppant, has a specific gravity of about 2.65. Typical sand sizes are 20/40 sand and 40/70 sand, but 80/100 sand has also been used in the Marcellus Shale.^{69,70,71,72,73}

Current proppant research areas include improving proppant placement and reducing proppant flowback. Excessive proppant packing can reduce the fracture conductivity, whereas monolayer or partial monolayer placement can hold the fracture open while maximizing flow areas. Some studies have investigated reducing proppant flowback by coating the proppant particles in resin, by adding fibrous material to the frac fluid, and by using deformable proppants.^{74,75,76}

Before 1997, a high percentage of hydraulic fracturing stimulations used a crosslinked fluid and a heavy concentration of proppants. Many tight gas shale stimulation projects turned out to have low rates of return due to residue remaining in the proppant pack which reduced flow to the wellbore. As experience grew in the Barnett Shale, well developers experimented with thinner and less viscous fluids to reduce the required cleanup effort. In the Barnett Shale, common practice evolved to slickwater fracs with low proppant concentrations and various performance additives.⁷⁷

⁶⁹ The sizes of particles passing the #20, #40, #70, and #100 meshes are 0.331, 0.0165 in., 0.0083 in., and 0.0059 in., respectively.

⁷⁰ Brannon, Harold D., 2009. "Fracturing Materials," Presented at the SPE Hydraulic Fracturing Technology Conference, January 19-21, 2009, The Woodlands, Texas.

⁷¹ Martin, T., 2007. "Appropriate Hydraulic Fracturing Technologies for Mature Oil and Gas Formations," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Program.

⁷² Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁷³ Lambe, T. William, *Soil Testing for Engineers*, John Wiley & Sons, Inc., New York, 1951.

⁷⁴ Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, June 2006.

⁷⁵ Sharma, M.M. et al, 2003. "The Impact of Proppant Placement on the Productivity of Tight Gas Wells," *GasTIPS*, Fall 2003.

⁷⁶ Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, June 2006.

⁷⁷ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

Slickwater fracs generally use much lower proppant concentrations than conventional fracturing. Many wells have been successfully fractured with no proppant at all, but in some cases the high initial flow rates fell off shortly into production. Other horizontal wells in shale have attained commercial rates with only 5,000 to 10,000 lb. of proppant, although hundreds of thousands of pounds per well is more common in the Barnett Shale. Data on seven stimulation designs in Barnett Shale wells from 2001 to 2007 show proppant concentrations of 0.15 to 1.02 pounds of sand per gallon of frac fluid, and from 200 to 1500 lb per horizontal foot of well, with the higher sand quantities corresponding to multistage stimulations. An analysis of 3400 frac stages completed in 2008 in the Woodford Shale in Oklahoma and the Barnett Shale reported the total amount of proppant used equaled 1,100,000,000 lb., or 323,500 lb. per stage. Limited data for typical slickwater stimulations in the Marcellus shale indicate that proppant concentrations around 1.0 lb/gal have been successful.^{78,79,80,81,82}

1.1.4.3 Additives

Fracturing fluids are enhanced with additives designed to enhance specific engineering properties. The additives may include friction reducers, surfactants, gelling agents, crosslinking compounds, breakers, biocides, oxygen scavengers, scale inhibitors, acids, iron control agents or clay stabilizers. Friction reducing agents reduce the pumping pressure required to deliver frac fluid to the area to be fractured at a given rate and at the design pressure, and therefore reduce the number and power of pumping trucks required. Surfactants are used primarily to increase the fluid viscosity for better proppant transport. Biocides inhibit the growth of potentially pore-clogging microorganisms in the induced and propped fractures. Oxygen scavengers reduce corrosion to the well bore piping. Scale inhibitors reduce the buildup of deposits from precipitating metals and minerals in the pore spaces in and near the wellbore where the water chemistry changes most significantly. Acids can be used to clean up, or break, the viscosity or residue caused by other fluid additives, and can also be used to increase the porosity of the rock matrix itself. Acid can also be used to dissolve acid-soluble cement that has been injected to provide temporary isolation of targeted fracture zones. Clay stabilizers help to reduce the release of fine clay particles from the surface of the fractured shale.^{83,84,85}

Common friction reducing chemicals include polyacrylamides. Polyacrylamides are usually added at the rate of 250 to 1,000 ppm. Because friction reducers can combine with fine mineral particles and liquid hydrocarbons, friction reducer defloculants may be added to reduce the formation of such pore and fracture clogging material.^{86,87}

⁷⁸ Bybee, Karen, 2009. "Technology Focus: Hydraulic Fracturing," *Journal of Petroleum Technology*, Society of Petroleum Engineers, March 2009.

⁷⁹ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁸⁰ Halliburton, 2008. "Trends in Unconventional Gas," Articles from *Oil and Gas Journal*, 2007-2008.

⁸¹ Matthews, H. Lee, "Overview of Shale Gas Stimulation Techniques," Search and Discovery Article #40335, Adapted from oral presentation at AAPG Annual Convention, April 20-23, 2008, San Antonio, Texas.

⁸² Heinze, Jim, "Stimulation in Gas Shales," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

⁸³ Bybee, Karen, 2009. "Technology Focus: Hydraulic Fracturing," *Journal of Petroleum Technology*, Society of Petroleum Engineers, March 2009.

⁸⁴ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

⁸⁵ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁸⁶ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁸⁷ Halliburton, 2008. "Trends in Unconventional Gas," Articles from *Oil and Gas Journal*, 2007-2008.

A recent development is the use of special surfactants together with an electrolyte such as quaternary ammonium salt to increase viscosity by creating long molecular structures called micelles in water based fluids. Since oil or gas hydrocarbons break up micelles, the fractures and proppant pores are cleaned up during production without the need to introduce additional breakers.⁸⁸

Acids used for cleanup or to increase porosity can also dissolve and mobilize naturally occurring metals. Although most shale minerals do not dissolve in acid, shale can contain distributed acid-soluble minerals within the rock matrix. Weak acids have been used to dissolve these minerals to increase the microporosity of the fracture surfaces and of the shale matrix itself, leading to up to 100% increases in initial gas flow rates.⁸⁹

In 2004, the U.S. EPA summarized information on hydraulic fracturing fluids and additives used to stimulate coalbed methane wells. Although the EPA study deals exclusively with coalbed methane deposits, similar materials are also used in other types of geologic formations. Attachment 1 reproduces the EPA summary table of fracture fluid and additive characteristics and hazards.⁹⁰ The table is not meant to indicate any specific human health or ecological risks, but broadly describes the potential hazards and toxicity associated with the undiluted form of chemicals in common frac additives. Although exposure to some of the identified chemicals in concentrated form could lead to human health impacts, the concentrations are less than 100% in the hydraulic fracturing additives, the additives are generally greatly diluted in the frac fluid, and the frac fluid may be further diluted by groundwater in the target formation. Not all of the listed chemicals have been proposed for use in New York State to date.

A comparison of 267 chemical components of fracture fluid additives compiled by NYDEC and proposed for use in New York State to the list of hazardous substances in 6 NYCRR Part 597 yielded 41 matches.⁹¹

Analysis of recovered frac fluids indicates that some chemical additives may have lower recovery rates than the fracturing fluid itself. One analysis of the returned fluid from ten wells in a tight gas sandstone demonstrated that although only 48% of the injected water remained in the formation, 65% of the polymer additive remained behind.⁹² Laboratory tests in long sand-packed columns indicated that some surfactants adsorbed rapidly to shale minerals, and therefore would not be expected to be removed during flowback. Therefore, chemical concentrations of some additives in the formation may be different than and greater than the concentrations in the hydraulic fracturing fluid itself.⁹³

In the Marcellus Shale, most hydraulic fracturing is currently performed with water based slickwater fracturing fluids which may contain additives to reduce friction, prevent corrosion, or cleanup or prevent clogging. Slickwater with concentrations of 5 pounds per thousand gallons of

⁸⁸ Malpani, R.V., December 2006. *Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs*, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

⁸⁹ Halliburton, 2008. "Trends in Unconventional Gas," Articles from *Oil and Gas Journal*, 2007-2008.

⁹⁰ U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

⁹¹ 6 NYCRR Part 597, "List of Hazardous Substances"

⁹² Willberg, D.M., R.J. Card, L.K. Britt, M. Samuel, K.W. England, K.E. Cawiezel, H. Krus. 1997. "Determination of the Effect of Formation Water of Fracture Fluid Cleanup Through Field Testing in the East Texas Cotton Valley." In Proceedings-SPE Annual Technical Conference and Exhibition, October 5-8, 1997, Society of Petroleum Engineers, SPE #38620. pp. 531-543.

⁹³ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

water (ppt) of friction reducer, 0.25 gallons per thousand (gpt) of biocide, and 2 gpt of microemulsion additives have reportedly been successful in the Marcellus Shale.⁹⁴

The Pennsylvania Department of Environmental Protection (PADEP) has compiled a table of the hazardous components listed on the Material Safety Data Sheets (MSDS) provided by fracturing contractors with activities in the Marcellus Shale in Pennsylvania.⁹⁵ The table appears as Attachment 2. Although the additives in the PADEP list may not necessarily match those proposed for use in New York State, and although the concentrations may differ based on variations in the fracturing approach of individual operators, the list is informative in that it provides the concentrations of the chemical components after dilution in the frac fluid and compares these concentrations to the EPA risk-based concentrations for residential tapwater. Many of the components listed do not have established levels for drinking water. Of those that do, only a few alcohols (propargyl alcohol, methanol, ethylene glycol) exceed the drinking water standards.

1.1.5 Confining the vertical and lateral extent of fracturing

Well developers have strong financial incentives to restrict the development of fractures during hydraulic fracturing to the target formation. The creation of fractures into overlying or underlying formations increases the quantity of fracturing fluid and proppants required, increases the duration of the fracturing operations, requires more surface fluid storage capacity and fluid handling equipment, and can allow more production water to flow into the well. These conditions add to the costs of well stimulation, increase water treatment and disposal costs, and lead to less than optimum production results.

1.1.5.1 How fractures develop

Hydraulic fracturing, either naturally occurring or artificially induced, uses high fluid pressure to open existing joints or to create new joints in the rock mass. In order to open a joint, the fluid pressure must exceed the compressive stresses in the rock. The state of stress in a solid material can be defined by three orthogonal normal stresses, called the major, intermediate, and minor principal stresses. Since the minor principal stress has the lowest value, the fluid pressure exceeds the minor principal stress first and opens a joint perpendicular to its direction. By definition, the plane of joint propagation coincides with the directions of the major and intermediate principal stresses.

In depositional strata, gravity forces increase the vertical stress as the thickness of the deposited layer increases. The vertical pressures try to expand the material laterally as they compress it vertically, but since the strata are essentially infinite in horizontal extent relative to their thickness, the lateral expansion is constrained by the adjacent material. Horizontal compressive stresses develop to offset the lateral expansion, holding each unit volume of material to its original horizontal dimensions. Initially, the horizontal compressive stresses are often nearly uniform in every direction, so the minor and intermediate principal stresses are nearly equivalent.

As geologic time passes, erosional processes can remove overburden, decreasing the vertical stress. The horizontal stress decreases at a slower rate than does the vertical stress as material erodes. This process results in an increasing ratio of horizontal stress to vertical stress in strata

⁹⁴ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

⁹⁵ PADEP, Undated. "Table 1, Summary of Hydraulic Fracture Solutions – Marcellus Shale."

that now lie closer to the surface. Within a several thousand feet of the surface, the ratio often exceeds 1.0 indicating that the major principal stress has rotated from the vertical towards the horizontal.⁹⁶

If hydraulic fractures, either natural or induced, develop in a geologic formation at a depth where the minor principal stress is horizontal, fractures would develop in the vertical plane. In strata lying closer to the surface where the minor principal stress has rotated closer to the vertical due to past erosion, natural or hydraulically induced fractures would tend to curve toward the horizontal. Evidence of such fracture curvature near the earth's surface can be seen in natural fractures in the Marcellus Shale in Union Springs, New York.⁹⁷

In addition to the uniform stress field created during deposition and uniform erosion, additional stress components arise due to non-uniform erosion, folding, and uplift that create topographic features and corresponding topographic stresses. These differential stresses tend to die out at depths approximating the scale of the topographic features. In the Appalachian Basin, the stress state would be expected to lead to predominantly vertical fractures below about 2500 feet, with a tendency towards horizontal fractures at shallower depths.⁹⁸

1.1.5.2 Natural fractures

Potential unconventional gas plays in New York include but are not limited to the Marcellus Shale, Utica Shale, Medina sandstones, and the Theresa Sandstone.⁹⁹ Information on the characteristics of the shales appears in Table 2.

Table 2: Comparison of New York State Shales^{100,101}

	Utica Shale	Marcellus Shale
Age	Upper Ordovician	Mid-Devonian
Porosity	3.70%	4 – 9%
Total Organic Content	2.06%	4 – 6%
Thickness, ft	1,000	80 – 100

The Marcellus Shale has multiple natural sets of vertical fractures, caused either by uplift and erosion or by natural hydraulic fracturing. The Marcellus Shale is overlain by thousands of feet of siltstone and shale formations of the Middle and Upper Devonian periods. Intact shales are generally considered barriers to the vertical migration of fluids. If the overlying strata also contain vertical fracture sets, such fractures could reduce the ability of these strata to impede vertical flow.^{102,103}

⁹⁶ Brown, E.T. and Hoek, E., 1978, Trends in relationships between measured in situ stresses and depth, *International Journal of Rock Mechanics and Mining Science*, v. 15, p. 211-215.

⁹⁷ Engelder, Terry, 2008, "Structural geology of the Marcellus and other Devonian gas shales: Geological conundrums involving joints, layer-parallel shortening strain, and the contemporary tectonic stress field," Department of Geosciences, The Pennsylvania State University.

⁹⁸ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

⁹⁹ NYSERDA, 2007, *New York's Natural Gas and Oil Resource Endowment: Past, Present and Potential*.

¹⁰⁰ Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

¹⁰¹ Different investigators may report different values for the physical parameters. The values shown should be considered approximate.

¹⁰² Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

¹⁰³ Engelder, Terry and Gary G. Lash, 2008, "Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia", *The American Oil & Gas Reporter*, May 2008.

Several geologists make a compelling case that the most prominent joint set in the Marcellus Shale was caused by natural hydraulic fracturing. According to this theory, fluid pressures created during hydrocarbon generation exceeded the in situ horizontal stress and drove vertical fractures upward out of the Marcellus and other black shales and into the gray shales above.^{104,105}

This vertical joint set in the Marcellus Shale has typical spacing frequently less than one meter and strikes ENE (60° to 75°), perpendicular to the existing minimum principal stress. Induced hydraulic fracturing along horizontal wells is more likely to reopen this joint set rather than create new fractures, so the wells should be drilled in the NNW or SSE directions to optimize the intersection of these fractures for maximum gas production.¹⁰⁶

1.1.5.3 Induced fractures

In situ stress is perhaps the most important parameter to determine the orientation and direction of artificially induced fractures. Whenever the fluid pressure exceeds the minimum normal stress in the rock mass plus whatever minimal tensile stress the rock may have, the rock will fracture. As the fracture width widens, more fluid must be pumped in at the same or greater pressure to keep the crack open and to make it grow. As the surface area of the fracture increases, more fluid is lost to the surrounding formation and it requires higher flow rates and greater pumping pressure to maintain an open fracture.

Fractures will preferentially grow toward lower stress regions, so vertical growth is typically upward instead of downward. Fractures may cross into an overlying stratum, or may stop, depending in part on the differences in the moduli and stresses in the two strata.¹⁰⁷

1.1.5.4 Strategies to limit fracture growth

The mechanisms that limit fracture growth are not completely understood. Several mechanisms have been postulated to explain the physical processes which may limit vertical fracture development, such as stress contrast or modulus contrast between the formation where fractures initiate and the overlying stratum, but laboratory and field experiments have shown that fractures can still develop across the interface between two strata despite significant contrast. More recent work suggests that shear failure, or slippage, at the fracture tip may blunt the tip and impede local fracture growth.^{108,109}

Well developers can attempt to limit the vertical and lateral extent of fractures by performing pre-stimulation modeling and trying to develop a stimulation treatment that produces fractures of

¹⁰⁴ Engelder, Terry, 2008, "Structural geology of the Marcellus and other Devonian gas shales: Geological conundrums involving joints, layer-parallel shortening strain, and the contemporary tectonic stress field," Department of Geosciences, The Pennsylvania State University.

¹⁰⁵ Engelder, Terry and Gary G. Lash, 2008, "Science behind the Marcellus Play, The Devonian Black Shale Play of the Appalachian Basin".

¹⁰⁶ Lash, Gary G., 2008. "Stratigraphy and Fracture History of the Middle and Upper Devonian Succession, Western New York – Significance to Basin Evolution and Hydrocarbon Exploration", Dept. of Geosciences, SUNY Fredonia, New York.

¹⁰⁷ Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, June 2006.

¹⁰⁸ Fokker, Peter, 2007. "Hydraulic Fracturing," TNO Built Environment and Geosciences, Geological Survey of the Netherlands, The Netherlands.

¹⁰⁹ Daneshy, A.A., 2009. "Factors Controlling The Vertical Growth of Hydraulic Fractures," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

the dimensions desired. The success of this approach depends on the extent of the characterization of the rock mass, adherence of the stimulation treatment to the conditions modeled, and the ability of the model to predict fracture dimensions. Since the characterization of the rock mass is always incomplete and since even the best currently available models only approximate the physical processes, pre-fracture simulations can only approximate the extent of induced fractures.

The use of fracture measurement techniques can help well developers to fine-tune their estimates by comparing the created fracture dimensions to the predicted dimensions, and adjusting details of the fracture treatments to increase the probability of achieving fractures of the design dimensions. For example, use of a friction reducer can help increase the fracture length while limiting the fracture height by reducing pumping losses within fractures, thus maintaining higher fluid pressure at the fracture tip.¹¹⁰ Since microseismic analysis can measure fracture growth nearly in real-time, the fracturing process can be closely monitored and stopped when the design fracture size has been achieved.

Well developers can also improve control of the hydraulic fracturing process by reducing the length of well bore fractured in each stage. Zones can be isolated along the wellbore by packers, shunts, or other mechanical means to focus the fracturing pressure and the proppant placement to limited target zones and to better understand the fracture development by more closely relating the pumping pressures and volumes to that single zone. Some proprietary techniques such as jet-perforated multi-stage completions or hydra-jetting control fracturing pressure to a single fracture using the hydraulic principles of high pressure jets rather than mechanical devices such as packers.^{111,112}

1.1.5 “Re-fracking” in developed reservoirs

1.1.5.1 Pros and cons of refracturing

The ultimate objective of refracturing is the same as for the original fracturing, i.e. to improve the return on investment of the well. Refracturing is most commonly performed on a producing well when the production rate has significantly declined below its historic rate. Apart from partial depletion of the gas reserves and the concomitant pressure drop, the primary reason for production declines in wells that have been hydraulically fractured is a reduction in the conductivity into or along the fractures. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary. Refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture zone.^{113,114}

Wells may be refractured multiple times, may be fractured along sections of the wellbore that were not previously fractured, and may be subject to variations from the original fracturing technique. Changes in formation stresses due to the reduction in pressure from production can

¹¹⁰ Railroad Commission of Texas, 2008. “Water Use in the Barnett Shale,” URL: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php, July 30, 2008.

¹¹¹ Schlumberger, 2003, *Services*, “DataFRAC Service.”

¹¹² Halliburton, 2007. “Advances in Unconventional Gas”. Hart Energy Publishing, Houston, Texas.

¹¹³ Halliburton, 2008. “Trends in Unconventional Gas,” Articles from *Oil and Gas Journal*, 2007-2008.

¹¹⁴ Martin, T., 2007. “Appropriate Hydraulic Fracturing Technologies for Mature Oil and Gas Formations,” Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Program.

sometimes cause new fractures to propagate at a different orientation than the original fractures, further extending the fracture zone.

Factors which may influence an operator to forego or delay refracturing include economic considerations such as tight capital markets or not interrupting production while gas prices are high, and technical considerations such as insufficient production gains from refracturing in other wells in the same formation. In the Barnett shale an additional technical consideration would concern the potential of extending fractures into the underlying Ellenberger formation and producing saline water. No known similar water bearing formation bounds the Marcellus shale in New York.

1.1.5.2 Effectiveness of refracturing

Refracturing often boosts the production rate by 50% to 100% and can frequently restore the well's production rate close to between 75% and 100% of the initial rate, although the post-fracture production rate would be expected to be lower with each subsequent refracturing treatment.^{115,116} Increases in the production rate of over 1500% have been reported in some isolated case histories, whereas in other cases the refracturing has been determined to be not cost effective. The variety of factors that determine the cost effectiveness of a refracturing stimulation - including the characteristics of the geologic formation, the cost of stimulation, the market price for gas, and the time value of money - make it difficult to draw simple comparisons or guidelines.

Past studies of reservoir productivity indicate that production following the completion and initial fracturing of a shale well recovers only about 10% of the gas in place (GIP). Refracturing the well can increase the cumulative amount of gas recovered by 80% to 100%. By boosting the production rate and the ultimate amount of gas recovered, refracturing can greatly extend the economic life of a well.^{117,118,119}

1.1.5.3 Frequency

Developers may decide to refracture a well whenever the production rate declines significantly below past production rates or below the estimated reservoir potential. The decisions whether to refracture, when to refracture, and how often to refracture primarily depend on the expected economic return. Factors that go into the decisions include past well production rates, experience with other wells in the same formation, the costs of refracturing, and the current price for gas.

Hydraulically fractured wells in tight gas shale often experience production rate declines of over 50% in the first year. Fractured Barnett shale wells generally would benefit from refracturing within 5 years of completion, but the time between fracture stimulations can be less than 1 year or greater than 10 years.¹²⁰

¹¹⁵ Martin, T., 2007. "Appropriate Hydraulic Fracturing Technologies for Mature Oil and Gas Formations," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Program.

¹¹⁶ Halliburton, 2007. "Advances in Unconventional Gas". Hart Energy Publishing, Houston, Texas.

¹¹⁷ Halliburton, 2008. "Trends in Unconventional Gas," Articles from *Oil and Gas Journal*, 2007-2008.

¹¹⁸ PTTC, 2006. *PTTC Appalachian Region Newsletter*, Fall 2006, Vol. 7, No. 2.

¹¹⁹ Halliburton, 2007. "Advances in Unconventional Gas". Hart Energy Publishing, Houston, Texas.

¹²⁰ Schlumberger, 2009. "Case Study: StimMORE Service Increases EUR in Barnett Shale Well by 0.25 Bcf, Integrated approach results in daily production increase of nearly threefold."

A review of several case histories of Barnett shale wells suggests that refracturing is often performed when the production decline is between 50% and 85% relative to the rate in the first few months of production.^{121,122}

1.1.6 Cost

Keys to a cost-effective frac job are to use the appropriate technology for the treatment, to make use of economies of scale to reduce the fixed costs per unit of production, and to avoid false economies.¹²³

An early step in the evaluation of shale exploitation scenarios involves deciding whether to install vertical or horizontal wells. Vertical wells are much less expensive, but tap into a much smaller volume of the reservoir, especially in a relatively thin formation such as the Marcellus. Costs for a well in the Marcellus are estimated at between \$800,000 and \$1,300,000 for a vertical well and between \$2.5 million and \$4 million for a horizontal well, plus the costs for the well pad and infrastructure. It may take four vertical wells to cover an area as effectively as with a single horizontal well. Since horizontal wells can be drilled in different directions from a single well pad, a horizontal well pad supporting four horizontal wells can replace sixteen vertical well pads.¹²⁴

In 2007, Conoco Philips spent \$194.4 million on 2,114 fracture jobs in the continental US, or an average of \$92,000 per job.^{125,126} Data from Philips Petroleum, Amax Oil and Gas, and Amoco provide similar costs, with typical gel fracs costing \$50,000 to \$100,000 and water fracs costing about half as much. Water fracs, such as the slickwater fractures likely to be used in the Marcellus Shale, cost significantly less than gel fractures and often produce higher production rates because they use less expensive materials and cause less formation damage.

1.1.7 Conclusions

Hydraulic fracturing analysis, design, and field practices have advanced dramatically in the last quarter century. Materials and techniques are constantly evolving to increase the efficiency of the fracturing process and increase reservoir production. Analytical techniques to predict fracture development, although still imperfect, provide better estimates of the fracturing results. Perhaps most significantly, fracture monitoring techniques are now available that provide confirmation of the extent of fracturing, allowing refinement of the procedures for subsequent stimulation activities to confine the fractures to the desired production zone.

The hydraulic fracturing fluids most likely to be used in New York State consist primarily of fresh water, with additives making up perhaps 1 to 2%. The fracturing fluid additives still include chemicals which could pose potential hazards in concentrated form but which are typically diluted several orders of magnitude when mixed with the fracturing fluid. The development of water frac technologies for unconventional gas development has reduced the quantity of chemicals required to hydraulically fracture target reservoirs.

¹²¹ Martin, T., 2007. "Appropriate Hydraulic Fracturing Technologies for Mature Oil and Gas Formations," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Program.

¹²² Halliburton, 2007. "Advances in Unconventional Gas". Hart Energy Publishing, Houston, Texas.

¹²³ Martin, T., 2007. "Appropriate Hydraulic Fracturing Technologies for Mature Oil and Gas Formations," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Program.

¹²⁴ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

¹²⁵ Flesher, Robert, 2009. "Stimulation in Tight Gas Sands," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

¹²⁶ This fracture data may include costs for both oil and gas wells and formations other than shale.

The following sections discuss in greater detail the physical and chemical processes associated with hydraulic fracturing which could lead to or prevent potential adverse environmental impacts.

SUBTASK 1.2: SUBSURFACE MOBILITY OF FRACTURING FLUIDS AND ADDITIVES

This section deals with the potential adverse environmental impacts of the migration of hydraulic fracturing fluid or its constituents from the fracture zone. Specifically, it addresses the mechanisms and bounding characteristics for migration of frac fluid components between a fracture zone and a potential aquifer.

1.2.1 Potential exposure pathways

Drilling fluids in general, not just hydraulic fracturing fluids, have the potential to adversely impact surface water and groundwater if not properly handled. Constituents of drilling fluids may come into contact with water supplies along three primary pathways related to drilling operations involving hydraulic fracturing and subsequent production. These pathways are surface spills, casing leaks, or migration from the production zone.

The first and most common source of contamination is from inadequate material handling practices at the surface. Spills and overflows of drilling fluids, flowback, product, or wastewater can seep into shallow groundwater aquifers or run off into surface water bodies. Proper site management techniques can reduce or eliminate these risks. However, this topic is not addressed in this report as it is outside the scope of this study.

The second potential source of contamination relates to leaks associated with improperly constructed casings or failure of properly constructed casings. Regulations in most drilling states, including New York, have specific criteria for casing design, cementing, and testing. Poor casing construction or cementing practices can lead to leaks through the casing or vertical fluid movement in the annulus outside of the casing. In the 1980s, the American Petroleum Institute analyzed the risk of contamination from properly constructed Class II injection wells to an Underground Source of Drinking Water (USDW) due to corrosion of the casing and failure of the casing cement seal. Although the API study did not address the risks for production wells, production wells would be expected to have a lower risk of groundwater contamination due to casing leakage. Unlike Class II injection wells which operate under sustained or frequent positive pressure, a hydraulically fractured production well experiences pressures below the formation pressure except for the short time when fracturing occurs. During production, the wellbore pressure must be less than the formation pressure in order for formation fluids or gas to flow to the well. Using the API analysis as an upper bound for the risk associated with the injection of hydraulic fracturing fluids, the probability of fracture fluids reaching a USDW due to failures in the casing or casing cement is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells).¹²⁷

The third potential avenue of contamination is the migration of drilling and fracturing chemicals from the target zones, either during injection itself or from the frac fluid that remains in the formation after flowback. The likelihood of such migration reaching an aquifer depends on the distance between the target formation and the aquifer, the flow conditions, and the characteristics of the intervening materials. The low porosity and low permeability of shale formations makes them generally unsuitable as water sources. Table 3 compares the depth of several shale deposits to the approximate maximum depth of treatable water suitable for a potential drinking water supply. Most of the target shales lie several thousand feet below any potential drinking water aquifers.

¹²⁷ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

Table 3: Comparison of Depths to Shale Deposits and Potential Aquifers^{128,129}

Gas Shale	Shale Thickness, ft	Shale Depth, ft	Maximum Aquifer Depth, ft
Barnett TX	100 - 600	6,500 – 8,500	1,200
Fayetteville AR	20 - 200	1,000 – 7,000	500
Haynesville LA	200	10,000 – 13,500	400
Lewis NM	200 – 300	3,000 – 6,000	2,000
Marcellus NY, PA	50 - 200	4,000 – 8,500	850
Woodford OK	120 - 220	6,000 – 11,000	400

The discussion below deals solely with the third potential pathway, migration of hydraulic fracturing fluids or their components from the fracture zone to a groundwater aquifer.

1.2.2 Historic experience

The potential risks to groundwater aquifers from hydraulic fracturing have been studied previously. Much of the early experience with hydraulic fracturing involved the development of coalbed methane, so many of the early studies were focused on coalbed methane deposits.

Coalbed methane deposits are usually shallower than shale gas deposits and, unlike shale formations, the coalbed formations are frequently potential drinking water sources. In 1990, an Alabama state, federal, and industry task force concluded that hydraulic fracturing in coalbed deposits was unlikely to present any risk of groundwater contamination.¹³⁰ A 1998 survey of state agencies by the Ground Water Protection Council (GWPC) documented that there was not a single substantiated case of contamination of drinking water sources by hydraulic fracturing in over 10,000 coalbed methane wells in 13 states.¹³¹ U.S. EPA investigated the potential for contamination of coalbed aquifers, and concluded in 2004 that the injection of hydraulic fracturing fluids into coalbed methane wells poses little or no threat.¹³²

The potential risks to aquifers posed by hydraulic fracturing in tight gas shales would be expected to be even less than the risks posed from hydraulic fracturing in coalbed methane deposits because exploitable shale deposits are generally deeper, generally have greater vertical separation from potential aquifers, are generally of lower hydraulic conductivity than coal beds, and, unlike some coal beds, are not themselves aquifers.

Testimony by the GWPC before the House Committee on Natural Resources in June 2009 included statements from state officials in Ohio, Pennsylvania, New Mexico, Alabama, and Texas. Each of the states confirmed that there have been no incidents of groundwater contamination due to hydraulic fracturing.¹³³

¹²⁸ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

¹²⁹ In New York, the Marcellus Shale outcrops in some locations and some gas wells have been proposed at shallower depths than shown in the table.

¹³⁰ "Alabama lawsuit poses threat to hydraulic fracturing across US," *Drilling Contractor*, January/February 2000, p. 42-43.

¹³¹ Ground Water Protection Council, 1998, *Survey Results on Inventory and Extent of Hydraulic Fracturing in Coalbed Methane Wells in the Producing States*, December 15, 1998.

¹³² U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

¹³³ Ground Water Protection Council, 2009. "Statement of Scott Kell before the House Committee on Natural Resources Subcommittee on Energy and Mineral Resources", Washington, D.C., June 4, 2009.

1.2.3 Case studies of fracturing fluid migration

The literature review performed as part of the present study did not identify any published case histories or studies that included direct observation of the migration of frac fluids in hydraulically fractured shale.

Studies of fracturing fluid migration in geologic materials other than shale have shown some potential for migration beyond the propped portions of the induced fractures. In 2004, EPA summarized data on over two dozen mined-through studies in coalbed methane formations published between 1987 and 1993. In these studies, subsequent mining of subsurface coal seams allowed direct measurement of previous hydraulic fractures. Because shale does not have the economic value of coal and because shale gas formations are generally at much greater depths than coalbed methane deposits, there are no mined-through studies in shale.

The coalbed studies indicated that fracturing fluids follow the natural fractures and can migrate into overlying formations. EPA also reported that in half the cases studied, fracturing fluids migrated farther than and in more complex patterns than predicted. In several of the coalbed studies, the frac fluids penetrated hundreds of feet beyond the propped fractures either along unpropped portions of the induced fractures or along natural fractures within the coal.¹³⁴

1.2.4 Principles governing fracturing fluid flow

The mobility of hydraulic fracturing fluid depends on the same physical and chemical principles that dictate all fluid transport phenomena. Frac fluid will flow through the well, the fractures, and the porous media based on pressure differentials and hydraulic conductivities. In addition to the overall flow of the frac fluids, additives may experience greater or lesser movement due to diffusion and adsorption. The concentrations of the fluids and additives may change due to dilution in formation waters and possibly by biological or chemical degradation.

1.2.4.1 Limiting conditions

The analyses below present flow calculations for a range of parameters, with the intent to define reasonable bounds for the conditions likely to be encountered in New York State. Although one or more conditions at some future well sites may lie outside of the ranges analyzed, it is considered unlikely that the combination of conditions at any site would produce environmental impacts that are significantly more adverse than the worst case scenarios analyzed. The equations used in the analyses are presented below to facilitate the assessment of additional scenarios.

The analyses consider potentially useful aquifers with lower limits at depths up to 1,000 feet, somewhat deeper than the maximum aquifer depth reported in Table 3 for the Marcellus Shale. Similarly, the minimum depth to the top of the shale is taken as 2,000 ft, well above the minimum depth reported in Table 3 for the Marcellus Shale. The 2,000 ft. depth has been postulated as the probable upper limit for economic development of the New York shales.

The analyses include an additional conservative assumption. Even for deep aquifers, the analyses consider the pore pressure at the bottom of the aquifer to be zero as if a deep well or well field was operating at maximum drawdown. This assumption maximizes the potential for upward flow of fracturing fluid or its components from the fracture zone to the aquifer.

¹³⁴ U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

1.2.4.2 Gradient

For a fracturing fluid or its additives to have a negative impact on a groundwater aquifer, some deleterious component of the fracturing fluid would need to travel from the target fracture zone to the aquifer. In order for fluid to flow from the fracture zone to an aquifer, the *total head*¹³⁵ must be greater in the fracture zone than at the well. We can estimate the *gradient*¹³⁶ that might exist between a fracture zone in the shale and a potable water aquifer as follows:

$$i = \frac{h_{t1} - h_{t2}}{L} \quad (1)$$

where i = gradient
 h_{tn} = total head at Point n
 L = length of flow path from Point 1 to Point 2

Since the total head is the sum of the elevation head and the pressure head,

$$h_t = h_e + h_p \quad (2)$$

The gradient can be restated as

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} \quad (3)$$

where h_{en} = elevation head at Point n
 h_{pn} = pressure head at Point n

If the ground surface is taken as the elevation datum, we can express the elevation head in terms of depth.

$$d_n = -h_{en} \quad (4)$$

Restating the gradient yields

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} = \frac{(-d_1 + h_{p1}) - (-d_2 + h_{p2})}{L} = \frac{(d_2 - d_1) + (h_{p1} - h_{p2})}{L} \quad (5)$$

where d_n = depth at Point n

We can estimate the maximum likely gradient by considering the combination of parameters which would be most favorable to flow from the hydraulically fractured zone to a potential groundwater aquifer. These include assuming the minimum possible pressure head in the aquifer and the shortest possible flow path, i.e. setting h_{p2} to zero to simulate a well pumped to the maximum aquifer drawdown and setting L to the vertical distance between the fracture zone and the aquifer, $d_1 - d_2$.

¹³⁵ Total head at a point is the sum of the elevation at the point plus the pore pressure expressed as the height of a vertical column of water.

¹³⁶ The groundwater gradient is the difference in total head between two points divided by the distance between the points.

The gradient now becomes

$$i = \frac{(d_2 - d_1) + h_{p1}}{|d_1 - d_2|} \quad (6)$$

The total vertical stress in the fracture zone equals

$$\sigma_v = d_1 \times \gamma_R \quad (7)$$

where σ_v = total vertical stress
 d_1 = depth at Point 1, in the fracture zone
 γ_R = average total unit weight of the overlying rock

The effective vertical stress, or the stress transmitted through the mineral matrix, equals the total unit weight minus the pore pressure. For the purposes of this analysis, the pore pressure is taken to be equivalent to that of a vertical water column from the fracture zone to the surface. The effective vertical stress is given by

$$\sigma'_v = \sigma_v - (d_1 \times \gamma_w) \quad (8)$$

where σ'_v = effective vertical stress
 γ_w = unit weight of water

The effective horizontal stress and the total horizontal stress therefore equal

$$\sigma'_h = K \times \sigma'_v \quad (9)$$

$$\sigma_h = \sigma'_h + (d_1 \times \gamma_w) \quad (10)$$

where σ'_h = effective horizontal stress
 K = ratio of horizontal to vertical stress
 σ_h = total horizontal stress

The hydraulic fracturing pressure needs to exceed the minimum total horizontal stress. Allowing for some loss of pressure from the wellbore to the fracture tip, the pressure head in the fracture zone equals

$$h_{p1} = c \times \sigma_h = \frac{c \times d_1 \times [K(\gamma_R - \gamma_w) + \gamma_w]}{\gamma_w} \quad (11)$$

where h_{p1} = pressure head at Point 1, in the fracture zone
 c = coefficient to allow for some loss of pressure from the wellbore to the fracture tip

Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of

the geologic materials (estimated at 150 pcf average), times the depth.¹³⁷ To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress, yielding

$$h_{p1} = \frac{110\% \times d_1 \times [0.75(150 \text{ pcf} - 62.4 \text{ pcf}) + 62.4 \text{ pcf}]}{62.4 \text{ pcf}} = 2.26d_1 \quad (12)$$

Equation (6) thus becomes

$$i = \frac{(d_2 - d_1) + 2.26d_1}{|d_1 - d_2|} = \frac{d_2 + 1.26d_1}{|d_1 - d_2|} \quad (13)$$

Figure 1 shows the variation in the average hydraulic gradient between the fracture zone and an overlying aquifer during hydraulic fracturing for a variety of aquifer and shale depths. The gradient has a maximum of about 3.5, and is less than 2.0 for most depth combinations.

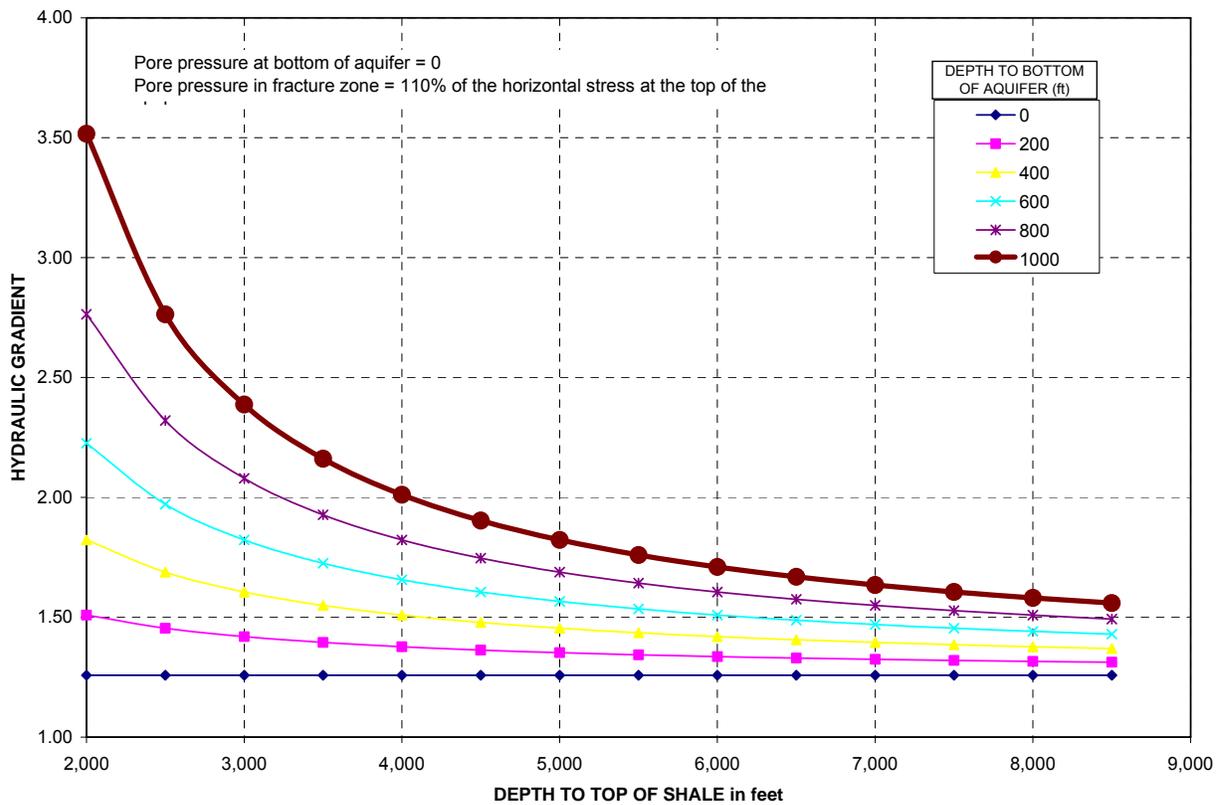


Figure 1: Average hydraulic gradient during fracturing

In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer

¹³⁷ Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

to the fracture zone and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied.

Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer. Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations.¹³⁸ During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow.

1.2.4.3 Seepage velocity

The second aspect to consider with regards to flow is the time required for a particle of fluid to flow from the fracture zone to the well. Using Darcy's law, the seepage velocity would equal

$$v = \frac{ki}{n} \quad (10)$$

where v = seepage velocity
 k = hydraulic conductivity
 n = porosity

The average hydraulic conductivity between a fracture zone and an aquifer would depend on the hydraulic conductivity of each intervening stratum, which in turn would depend on the type of material and whether it was intact or fractured. The rock types overlying the Marcellus Shale are primarily sandstones and other shales.¹³⁹ Table 4 lists the range of hydraulic conductivities for sandstone and shale rock masses. The hydraulic conductivity of rock masses tends to decrease with depth as higher stress levels close or prevent fractures. Vertical flow across a horizontally layered system of geologic strata is controlled primarily by the less permeable strata, so the average vertical hydraulic conductivity of all the strata lying above the target shale would be expected to be no greater than 1E-5 cm/sec and could be substantially lower.

Table 4: Hydraulic conductivity of rock masses¹⁴⁰

Material	Minimum k	Maximum k
Intact Sandstone	1E-8 cm/sec	1E-5 cm/sec
Sandstone rock mass	1E-9 cm/sec	1E-1 cm/sec
Intact Shale	1E-11 cm/sec	1E-9 cm/sec
Shale rock mass	1E-9 cm/sec	1E-4 cm/sec

Figure 2 shows the seepage velocity from the fracture zone to an overlying aquifer based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the seepage velocity would

¹³⁸ Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", *AAPG Bulletin*, March 1972, v. 56, No. 3, p. 528-536.

¹³⁹ Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.

¹⁴⁰ Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

be lower. For all of the analyses presented in this report, the porosity is taken as 10%, the reported total porosity for the Marcellus Shale.¹⁴¹ Total porosity equals the contribution from both micro-pores within the intact rock and void space due to fractures. For the overlying strata, the analyses also use the same value for total porosity of 10% which is in the lower range of the typical values for sandstones and shales. This may result in a slight overestimation of the calculated seepage velocity, and an underestimation of the required travel time and available pore storage volume.

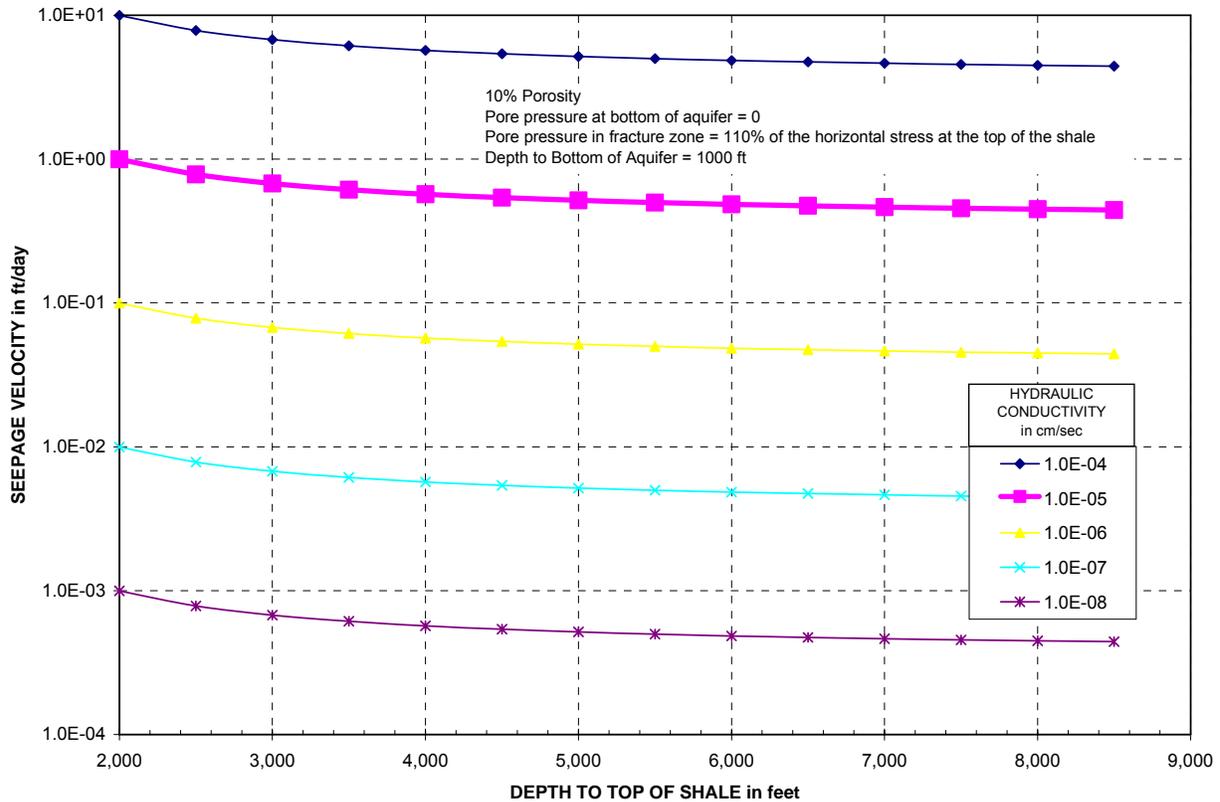


Figure 2: Seepage velocity as a function of hydraulic conductivity

Figure 2 shows that the seepage of hydraulic fracturing fluid would be limited to no more than 10 feet per day, and would be substantially less under most conditions. Since the cumulative amount of time that the fracturing pressure would be applied for all steps of a typical fracture stage is less than one day, the corresponding seepage distance would be similarly limited.

It is important to note that the seepage velocities shown in Figure 2 are based on average gradients between the fracture zone and the overlying aquifer. The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata.

¹⁴¹ DOE, Office of Fossil Energy, 2009. *State Oil and Natural Gas Regulations Designed to Protect Water Resources*, May 2009.

1.2.4.4 Required travel time

The time that the fracturing pressure would need to be maintained for the fracturing fluid to flow from the fracture zone to an overlying aquifer is given by

$$t = \frac{|d_2 - d_1|}{v} \tag{11}$$

where t = required travel time

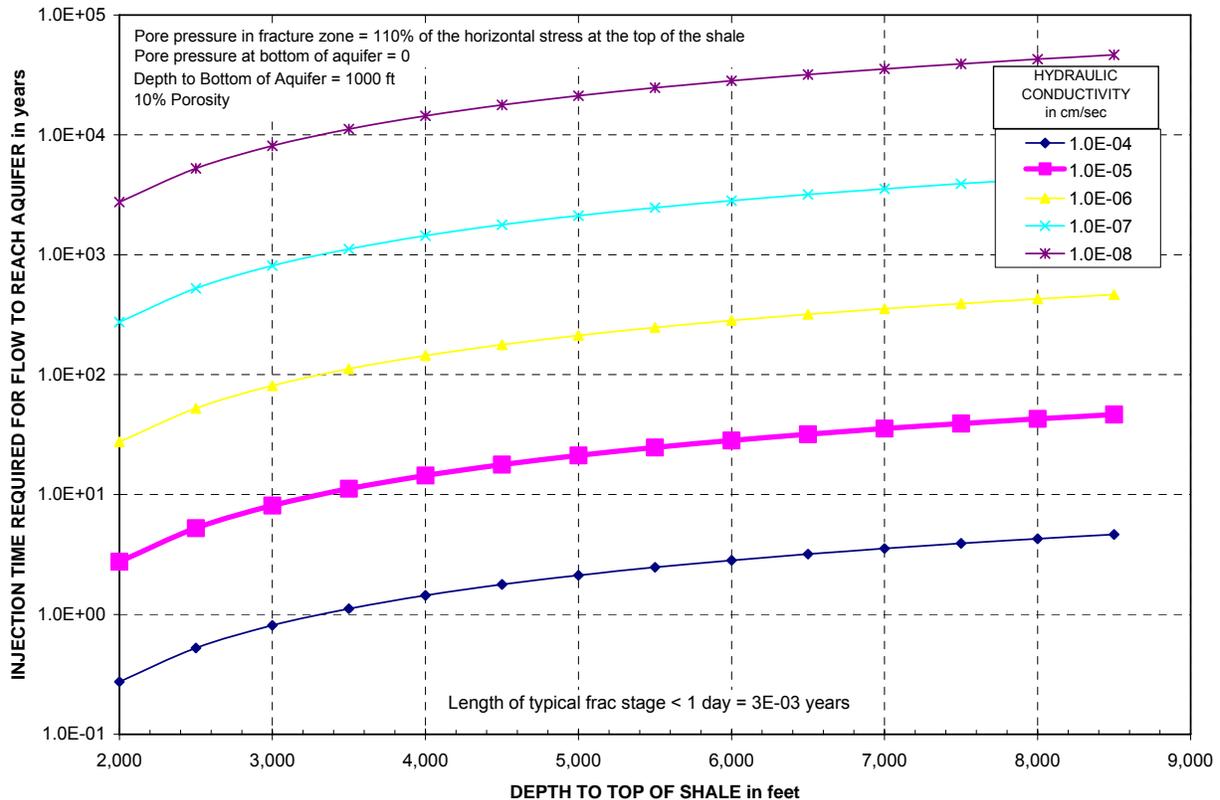


Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity

Figure 3 shows the required travel time based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the required flow time would be longer. The required flow times under the fracturing pressure is several orders of magnitude greater than the duration over which the fracturing pressure would be applied.

Figure 4 presents the results of a similar analysis, but with the hydraulic conductivity held at 1E-5 cm/sec and considering various depths to the bottom of the aquifer. Compared to a 1000 ft. deep aquifer, 10 to 20 more years of sustained fracturing pressure would be required for the fracturing fluid to reach an aquifer that was only 200 ft. deep.

The required travel times shown relate to the movement of the groundwater. Dissolved chemicals would move at a slower rate due to retardation. The retardation factor, which is the

ratio of the chemical movement rate compared to the water movement rate, is always between 0.0 and 1.0, so the required travel times for any dissolved chemical would be greater than those shown in Figures 3 and 4.

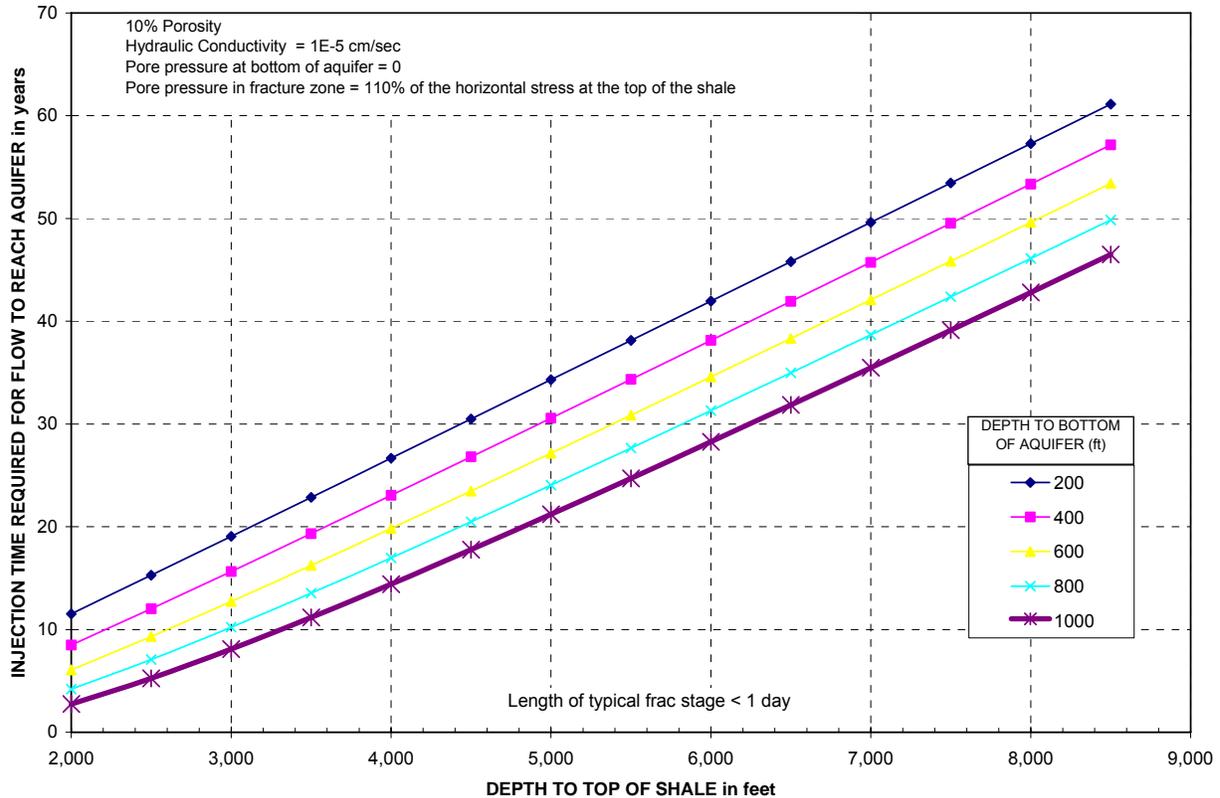


Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth

1.2.4.5 Pore storage volume

The fourth aspect to consider in evaluating the potential for adverse impacts to overlying aquifers is the volume of fluid injected compared to the volume of the void spaces and fractures that the fluid would need to fill in order to flow from the fracture zone to the aquifer. Figure 5 shows the void volume based on 10% total porosity for the geologic materials for various combinations of depths for the bottom of an aquifer and for the top of the shale, calculated as follows:

$$V = |d_1 - d_2| \times n \times \frac{43,560 \text{ ft}^2}{\text{acre}} \times \frac{7.48 \text{ gal}}{\text{ft}^3} \quad (12)$$

where V = volume of void spaces and fractures

A typical slickwater fracturing treatment in a horizontal well would use less than 4 million gallons of fracturing fluid, and some portion of this fluid would be recovered as flowback. The void volume, based on 10% total porosity, for the geologic materials between the bottom of an aquifer at 1,000 ft. depth and the top of the shale at a 2,000 ft. depth is greater than 32 million gallons per acre. Since the expected area of a well spacing unit is no less than the equivalent of

40 acres per well,^{142,143,144,145} the fracturing fluid could only fill about 0.3% of the overall void space. Alternatively, if the fracturing fluid were to uniformly fill the overall void space, it would be diluted by a factor of over 300. As shown in Figure 5, for shallower aquifers and deeper shales, the void volume per acre is significantly greater.

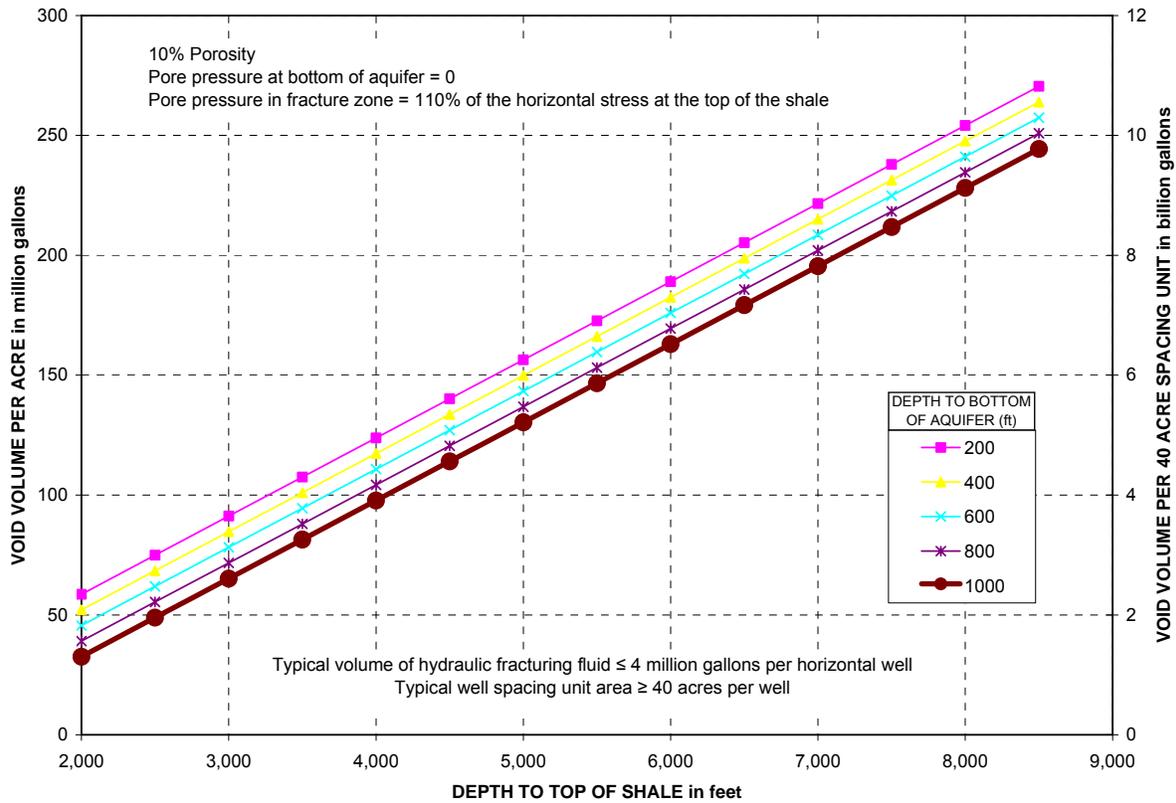


Figure 5: Comparison of void volume to frac fluid volume

1.2.5 Flow through fractures, faults, or unplugged borings

It is theoretically possible but extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer. The open flow path would have a much smaller area of flow leading to the aquifer and the resistance to flow would be lower. In such an improbable case, the flow velocity would be greater, the time required for the fracturing fluid to reach the aquifer would be shorter, and the storage volume between the fracture zone and the aquifer would be less than in the scenarios described above. The probability of such a combination of unlikely conditions occurring simultaneously (deep aquifer, shallow fracture

¹⁴² Infill wells could result in local increases in well density.

¹⁴³ New York regulations (Part 553.1 Statewide spacing) require a minimum spacing of 1320 ft. from other oil and gas wells in the same pool. This spacing equals 40 acres per well for wells in a rectangular grid.

¹⁴⁴ New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Part 553.1 Statewide spacing, (as of 5 April 2009).

¹⁴⁵ NYSDEC, 2009, "Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) on the Oil, Gas And Solution Mining Regulatory Program, Well Permit Issuance For Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-permeability Gas Reservoirs", February 2009.

zone, and open flow path) is very small. The fracturing contractor would notice an anomaly if these conditions led to the inability to develop or maintain the predicted fracturing pressure.

During flowback, the same conditions would result in a high rate of recapture of the frac fluid from the open flow path, decreasing the potential for any significant adverse environmental impacts. Moreover, during production the gradients along the open flow path would be toward the production zone, flushing any stranded fracturing fluid in the fracture or unplugged wellbore back toward the production well.

1.2.6 Geochemistry

The ability of the chemical constituents of the additives in fracturing fluids to migrate from the fracture zone are influenced not just by the forces governing the flow of groundwater, but also by the properties of the chemicals and their interaction with the subterranean environment. In addition to direct flow to an aquifer, the constituents of fracturing fluid would be affected by limitations on solubility, adsorption and diffusion.

1.2.6.1 Solubility

The solubility of a substance indicates the propensity of the substance to dissolve in a solvent, in this case, groundwater. The substance can continue to dissolve up to its saturation concentration, i.e. its solubility. Substances with high solubilities in water have a higher likelihood of moving with the groundwater flow at high concentrations, whereas substances with low solubilities may act as longer term sources at low level concentrations. The solubilities of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases such as the IUPAC-NIST Solubility Database.¹⁴⁶

The solubility of a chemical determines the maximum concentration of the chemical that is likely to exist in groundwater. Solubility is temperature dependent, generally increasing with temperature. Since the temperature at the depths of the gas shales is higher than the temperature closer to the surface where a usable aquifer may lie, the solubility in the aquifer will be lower than in the shale formation.

Given the depth of the New York gas shales and the distance between the shales and any overlying aquifer, chemicals with high solubilities would be more likely to reach an aquifer at higher concentrations than chemicals of low solubility. Based on the previously presented fluid flow calculations, the concentrations would be significantly lower than the initial solubilities due to dilution.

1.2.6.2 Adsorption

Adsorption occurs when molecules of a substance bind to the surface of another material. As chemicals pass through porous media or narrow fractures, some of the chemical molecules may adsorb onto the mineral surface. The adsorption will retard the flow of the chemical constituents relative to the rate of fluid flow. The retardation factor, expressed as the ratio of the fluid flow velocity to the chemical movement velocity, generally is higher in fine grained materials and in materials with high organic content. The Marcellus shale is both fine grained and of high organic content, so the expected retardation factors are high. The gray shales overlying the Marcellus

¹⁴⁶ IUPAC-NIST Solubility Database, Version 1.0, NIST Standard Reference Database 106, URL: <http://srdata.nist.gov/solubility/index.aspx>.

shale would also be expected to substantially retard any upward movement of fracturing chemicals.

The octanol-water partition coefficient, commonly expressed as K_{ow} , is often used in environmental engineering to estimate the adsorption of chemicals to geologic materials, especially those containing organic materials. Chemicals with high partition coefficients are more likely to adsorb onto organic solids and become locked in the shale, and less likely to remain in the dissolve phase than are chemicals with low partition coefficients.

The partition coefficients of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases. The partition coefficient is inversely proportional to solubility, and can be estimated from the following equation¹⁴⁷

$$\log K_{ow} = -0.862 \log S_w + 0.710 \quad (13)$$

where K_{ow} = octanol-water partition coefficient
 S_w = solubility in water at 20°C in mol/liter

Adsorption in the target black shales or the overlying gray shales would effectively remove some percentage of the chemical mass from the groundwater for long periods of time, although as the concentration in the water decreased some of the adsorbed chemicals could repartition back into the water. The effect of adsorption could be to lower the concentration of dissolved chemicals in any groundwater migrating from the shale formation.

1.2.6.3 Diffusion

Through diffusion, chemicals in fracturing fluids would move from locations with higher concentrations to locations with lower concentrations. Diffusion may cause the transport of chemicals even in the absence of or in a direction opposed to the gradient driving fluid flow. Diffusion is a slow process, but may continue for a very long time. As diffusion occurs, the concentration necessarily decreases. If all diffusion were to occur in an upward direction (an unlikely, worst-case scenario) from the fracture zone to an overlying freshwater aquifer, the diffused chemical would be dispersed within the intervening void volume and be diluted by at least an average factor of 160 based on the calculated pore volumes in Section 1.2.4.5. Since a concentration gradient would exist from the fracture zone to the aquifer, the concentration at the aquifer would be significantly lower than the calculated average. Increased vertical distance between the aquifer and the fracture zone due to shallower aquifers and deeper shales would further increase the dilution and reduce the concentration reaching the aquifer.

1.2.6.4 Chemical interactions

Mixtures of chemicals in a geologic formation will behave differently than pure chemicals analyzed in a laboratory environment, so any estimates based on the solubility, adsorption, or diffusion properties of individual chemicals or chemical compounds should only be used as a guide to how they might behave when injected with other additives into the shale. Co-solubilities can change the migration properties of the chemicals and chemical reactions can create new compounds.

¹⁴⁷ Chiou, Cary T., *Partition and adsorption of organic contaminants in environmental systems*, John Wiley & Sons, New York, 2002, p.57.

1.2.7 Conclusions

Analyses of flow conditions during hydraulic fracturing of New York shales help explain why hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers. Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The fracturing pressures which could potentially drive fluid from the target shale formation toward the aquifer are applied for short periods of time, typically less than one day per stage, while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone as pressures decline in the reservoir during production.

The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion. There are no known incidents of groundwater contamination due to hydraulic fracturing.

SUBTASK 1.3: REGULATORY ANALYSIS

1.3.1 New York State regulations

New York State regulations governing activities related to oil and gas resources are defined in Title 6, Department of Environmental Conservation, Chapter 5, Resource Management Services, Parts 550 through 559¹⁴⁸ and in the Environmental Conservation Law (ECL) Article 23.¹⁴⁹

New York State currently does not have any specific regulations for hydraulic fracturing, although regulations covering well drilling, completion, and production also apply to hydraulically fractured wells. In particular, New York regulations require:

- pollution prevention,
- groundwater protection,
- cementing of casing below the deepest freshwater zone,
- preventing migration of fluids between strata,
- drilling permits, and
- submission of well completion reports.

In addition, New York State has established detailed Casing and Cementing Procedures¹⁵⁰ and Fresh Water Aquifer Supplementary Permit Conditions¹⁵¹. Full disclosure of the chemical compositions of all additives used in hydraulic fracturing operations is required by DEC. DEC will not issue a well permit that proposes use of an additive whose full chemical composition is not on file. Companies may request trade secret status for proprietary additives. The Well Drilling and Completion Report filed after the well is drilled requires information on stimulation activities, including disclosure of the upper and lower depths of the zones stimulated, the type and volume of materials injected, the pumping rates, the breakdown pressure, the average treatment pressure, and the initial shut-in pressure.

1.3.2 Comparison with other shale gas states

Several other states have experienced recent increases in the number of hydraulic fracturing stimulations. The Fayetteville shale of Arkansas, the Haynesville shale of Louisiana, the Marcellus shale in Pennsylvania, and the Barnett shale of Texas are all tight gas shale formations that have been recently developed with stimulation techniques that are similar to those expected to be used in New York State.

Each of these states has rules or regulations governing groundwater protection, casing requirements, and cementing requirements. The required procedures are sufficient to prevent fracturing fluid from flowing upward along the wellbore and contacting water bearing strata adjacent to the borehole. Regulations also generally prohibit the migration of oil, gas or other fluids from one stratum to another.

¹⁴⁸New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Parts 550 through 559, as of 5 April 2009.

¹⁴⁹New York State, Environmental Conservation Law, Article 23, URL: <http://public.leginfo.state.ny.us>, accessed 4 August 2009.

¹⁵⁰NYDEC, Casing and Cementing Practices, URL: <http://www.dec.ny.gov/energy/1757.html>, accessed 14 July 2009.

¹⁵¹NYDEC, Fresh Water Aquifer Supplementary Permit Conditions, URL: <http://www.dec.ny.gov/energy/42714.html>, accessed 14 July 2009.

Neither New York nor any of the other states reviewed have regulations to collect information on potential fracture fluid mobility or to evaluate the driving flow mechanisms discussed in Section 1.2. Neither do they require well operators to provide information on the chemical components of the fracturing fluid in a manner that permits a simple evaluation of concentrations as injected. Neither the well permitting processes nor the well completion reports provide information on either the predicted extent of fracturing or on the actual, measured, fracture zone.

A summary of the regulatory comparison appears in Table 5, while Attachment 3 presents a more detailed comparison.

Table 5: Regulatory Comparison

	AR	LA	NY	PA	TX
Casing – pollution prevention			•	•	•
Casing – groundwater protection	•	•	•	•	•
Casing - Cementing	•	•	•	•	•
Testing well seals		•		•	•
Disclosure of fracture additives			•	•	
Completion reports	•	•	•	•	•
Additional logs	•	•		•	•
Regulations covering hydraulic fracturing		•	•	•	

The comparison in Attachment 3 and the summary in Table 5 focus on the regulations but may not cover all components of each state’s oversight of hydraulic fracturing activities. Other aspects of state programs, including environmental policy processes, guidance, manuals, or permit conditions may establish additional requirements.

1.3.3 Adequacy of New York State requirements

Based on the API analysis of Class II injection wells, the current New York State regulations for casing and cementing are sufficient to prevent migration of fluids along the wellbore, both during drilling and completion operations and during hydraulic fracturing.

Based on the characteristics and depth of the Marcellus shale formation in New York, one can make approximate calculations as in Section 1.2 to provide confidence that currently proposed approaches to hydraulic fracturing will not have reasonably foreseeable adverse environmental impacts on potential freshwater aquifers due to subsurface migration of fracturing fluids. The conditions under which the analyses support this conclusion include:

- maximum depth to the bottom of a potential aquifer $\leq 1,000$ ft
- minimum depth of the target fracture zone $\geq 2,000$ ft
- average hydraulic conductivity of intervening strata $\leq 1E-5$ cm/sec
- average porosity of intervening strata $\geq 10\%$

The calculations demonstrate that even under the combination of these conditions most favorable to flow, the pressures and volumes proposed for hydraulic fracturing are insufficient to cause migration of fluids from the fracture zone to the overlying aquifer in the short time that fracturing pressures would be applied. Conditions outside of these limits may require additional site-specific review.

1.3.4 Conclusions and recommendations

Not all of the exploitable gray and black shales may be as deep as the areas of the Marcellus currently envisioned for potential development, and future advances in technology may put shallower gas shales in play. If so, the separation between the target formations and potential aquifers may be smaller than the 1,000 foot vertical separation analyzed.

Fracturing technology continues to evolve. Future hydraulic fracturing conditions may differ significantly from the assumptions on which the analyses in Section 1.2 are based. Future fracturing fluids may change in chemical composition and fracturing practices may lead to the injection of larger quantities of fluid.

New York State could improve its ability to identify and evaluate reasonably foreseeable adverse environmental impacts from hydraulic fracturing operations associated with drilling and developing gas wells in low permeability gas reservoirs by instituting the following changes in its regulations or permit review procedures.

1. Require an inventory of nearby water wells within 1/4 mile of the drilled well.¹⁵²

The objective of this requirement would be to collect sufficient information to identify and to document any water wells most likely to be affected by drilling operations.

The drilling permit application should require the applicant to identify all water wells within 1/4 mile of the drilled well. This would also provide a notification mechanism for nearby water users. If well depth, drawdown, and pumping information is publicly available, DEC may consider having the applicant include this information. Some states, such as Alabama, already require a water well inventory.

2. Require information to confirm that the proposed well conditions are within the analyzed limits

The objectives of this requirement are to allow DEC to determine whether the conditions of the proposed well are within the limits analyzed, to identify any deviations from the analyzed conditions.

If the conditions are outside of the limits analyzed, the information will provide DEC with the data to perform a site-specific review. The drilling permit should specifically require the following information:

- maximum depth to the bottom of a potential aquifer
- minimum depth of the target fracture zone
- average hydraulic conductivity of intervening strata
- average porosity of intervening strata
- proposed volume of fracturing fluid

¹⁵² 1/4 mile equals the length of one side of a 40 acre square. Other distances may be proposed.

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ATTACHMENT 1: CHARACTERISTICS OF CHEMICALS IN HYDRAULIC FRACTURING FLUIDS¹⁵³

Product	Chemical Composition Information ¹	Hazards Information	Toxicological Information ²	Ecological Information
Linear gel delivery system	1) 30-60% by wt. Guar gum derivative 2) 60-100% by wt Diesel	<ul style="list-style-type: none"> • Harmful if swallowed • Combustible 	<ul style="list-style-type: none"> • Chronic effects/Carcinogenicity — contains diesel, a petroleum distillate and known carcinogen • Causes eye, skin, respiratory irritation • Can cause skin disorders • Can be fatal if ingested 	Slowly biodegradable
Water gelling agent	1) 60-100% by wt. Guar gum 2) 5-10% by wt. Water 3) 0.5-1.5% by wt. Fumaric acid	None	<ul style="list-style-type: none"> • Maybe mildly irritating to eyes 	Biodegradable
Linear gel polymer	1) <2% by wt. Fumaric acid 2) <2% by wt. Adipic acid	Flammable vapors	<ul style="list-style-type: none"> • Can cause eye, skin and respiratory tract irritation 	Not determined
Linear gel polymer slurry	1) 30-60% by wt. Diesel oil #2	<ul style="list-style-type: none"> • Causes irritation if swallowed • Flammable 	<ul style="list-style-type: none"> • Carcinogenicity — Possible cancer hazard based on animal data; diesel is listed as a category 3 carcinogen in EC Annex I • May cause pain, redness, dermatitis 	Partial1y biodegradable
Crosslinker	1) 10-30% by wt. Boric Acid 2) 10-30% by wt. Ethylene Glycol 3) 10-30% by wt. Monoethanolamine	<ul style="list-style-type: none"> • Harmful if swallowed • Combustible 	<ul style="list-style-type: none"> • Chronic effects/Carcinogenicity D5 may cause liver, heart, brain reproductive system and kidney damage, birth defects (embryo and fetus toxicity) • Causes eye, skin respiratory irritation • Can cause skin disorders and eye ailments 	Not determined
Crosslinker	1) 10-30% by wt. Sodium tetraborate decahydrate	May be mildly irritating: <ul style="list-style-type: none"> • to eyes and skin • if swallowed 	<ul style="list-style-type: none"> • May be mildly irritating 	<ul style="list-style-type: none"> • Partially biodegradable • Low fish toxicity
Foaming agent	1) 10-30% by wt. Isopropanol 2) 10-30% by wt. Salt of alkyl amines 3) 1-5% by wt. Diethanolamine	<ul style="list-style-type: none"> • Harmful if swallowed • Highly flammable 	<ul style="list-style-type: none"> • Chronic effects/Carcinogenicity — may cause liver and kidney effects • Causes eye, skin, respiratory irritation • Can cause skin disorders and eye ailments 	Not determined
Foaming agent	1) 10-30% by wt. Ethanol 2) 10-30% by wt. 2-Butoxyethanol 3) 25-55% by wt. Ester salt 4) 0.1-1% by wt. Polyglycol ether 5) 10-30% by wt. Water	Harmful if swallowed or absorbed through skin	<ul style="list-style-type: none"> • May cause nausea, headache, narcosis • May be mildly irritating 	Harmful to aquatic organisms

¹⁵³ U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

Product	Chemical Composition Information ¹	Hazards Information	Toxicological Information ²	Ecological Information
Acid treatment - hydrochloric acid	1) 30-60% by wt. Hydrochloric acid	<ul style="list-style-type: none"> • May cause eye, skin and respiratory burns • Harmful if swallowed 	<ul style="list-style-type: none"> • Chronic effects/Carcinogenicity — prolonged exposure can cause erosion of teeth • Causes severe burns, and skin disorders 	Not determined
Acid treatment - formic acid	1) 85% by wt. Formic acid	<ul style="list-style-type: none"> • May cause mouth, throat, stomach, skin and respiratory tract burns • May cause genetic changes 	<ul style="list-style-type: none"> • May cause heritable genetic damage in humans • Causes severe burns • Causes tissue damage 	Not determined
Breaker Fluid	1) 60-100% by wt. Diammonium peroxodisulphate	<ul style="list-style-type: none"> • May cause respiratory tract, eye or skin irritation • Harmful if swallowed 	<ul style="list-style-type: none"> • May cause redness, discomfort, pain, coughing, dermatitis 	Not determined
Microbicide	1) 60-100% by wt. 2-Bromo-2 nitrol,3-propanedol	<ul style="list-style-type: none"> • May cause eye and skin irritation 	<ul style="list-style-type: none"> • Chronic effects/Carcinogenicity — not determined • Can cause permanent eye damage, skin disorders, abdominal pain, nausea, and diarrhea if ingested 	Not determined
Biocide	1) 60-100% by wt. 2,2-Dibromo-3-nitripropionamide 2) 1-5% by wt. 2-Bromo-3-nitripropionamide	<ul style="list-style-type: none"> • Causes severe burns • Harmful if swallowed • May cause skin irritation; may cause allergic reaction upon repeated skin exposure 	<ul style="list-style-type: none"> • Harmful if swallowed; large amounts may cause illness • Irritant; may cause pain or discomfort to mouth, throat, stomach; may cause pain, redness, dermatitis 	Not determined
Acid corrosion inhibitor	1) 30-60% by wt. Methanol 2) 5-100% by wt. Propargyl alcohol	<ul style="list-style-type: none"> • May cause eye and skin irritation, headache, dizziness, blindness and central nervous system effects • May be fatal if swallowed • Flammable 	<ul style="list-style-type: none"> • Chronic effects/Carcinogenicity — may cause eye, blood, lung, liver, kidney, heart, central nervous system and spleen damage • Causes eye, skin, respiratory irritation • Can cause skin disorders 	Not determined
Acid corrosion inhibitor	1) 30-60% by wt. Pyridinium, 1-(Phenymethyl)-, Ethyl methyl derivatives, Chlorides 2) 15% by wt. Thiourea 3) 5-10% Propan-2-ol 4) 1-5% Poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy 5) 10-30% Water	<ul style="list-style-type: none"> • Cancer hazard (risk depends on duration and level of exposure) • Causes severe burns to respiratory tract, eyes, skin • Harmful if swallowed or absorbed through skin 	<ul style="list-style-type: none"> • Carcinogenicity —Thiourea is known to cause cancer in animals, and possibly causes cancer in humans • Corrosive – short exposure can injure lungs, throat, and mucus membranes; can cause burns, pain, redness swelling and tissue damage 	<ul style="list-style-type: none"> • Toxic to aquatic organisms • Partially biodegradable

1 Information presented is for the pure product, which is significantly diluted prior to injection. MSDS chemical composition percentages may total more than 100%.

2 Toxicity is concentration dependent.

ATTACHMENT 2: HYDRAULIC FRACTURING SOLUTIONS, MARCELLUS SHALE, PENNSYLVANIA¹⁵⁴

SUMMARY OF HYDRAULIC FRACTURE SOLUTIONS - MARCELLUS SHALE								
Product Vendor	Application Sequence	Product Name	Hazardous Components (From MSDS)	(From Hazardous Ingredient Weight %	Pounds of hazardous ingredient / pound water	Gallons of Frac solution per stage	Concentration in Frac Solution (ppm)	EPA Risk Based Concentration - Residential Tapwater (ppm)
BJS	1	HCl	Hydrochloric Acid	8%	0.015834	2000	83.68	
		CI-14	Propargyl Alcohol	5%	0.00004327	2000	0.23	0.073
			Methanol	68%	0.000588472	2000	3.11	18
		Ferrotrol 300L	Citric Acid	70%	0.0035	2000	18.50	
	2	XLW-32	Methanol	90%	0.001593	42000	176.79	18
			Boric Oxide	20%	0.000354	42000	39.29	
		GW-3LDF	Petroleum Distillate Blend	60%	0.00321	42000	356.24	
			Polysaccharide	60%	0.00321	42000	356.24	
		GBW-20C	no hazardous ingredients	0%	0	42000	0.00	
		BF-7L	Potassium Carbonate	100%	0.0005725	42000	63.53	
		GBW-15L	Sodium Chloride	14%	0.000154	42000	17.09	
	3	FRW-14	Hydrotreated light distillate	40%	0.000424	334000	374.20	
			Ethoxylated Alcohol	5%	0.000053	334000	46.77	
		Alpha 125	Glutaraldehyde	30%	0.0000798	334000	70.43	
Fractech	1	HCL	Hydrochloric Acid	8%	0.0168896	2000	89.26	
		40 HTL	Methanol	10%	0.0002	2000	1.06	18
		NE100	Methanol	5%	0.0000485	2000	0.26	18
		FE100L	no hazardous ingredients	0%	0	2000	0.00	
	2	HVG-04	no hazardous ingredients	0%	0	42000	0.00	
		B9	Potassium Hydroxide	20%	0.000206	42000	22.86	
		BXL-2	Potassium Hydroxide	10%	0.000117	42000	12.98	

¹⁵⁴ PADEP_HFSolutionsMarcellus.pdf

SUMMARY OF HYDRAULIC FRACTURE SOLUTIONS - MARCELLUS SHALE								
Product Vendor	Application Sequence	Product Name	Hazardous Components (From MSDS)	Hazardous Ingredient Weight %	Pounds of hazardous ingredient / pound water	Gallons of Frac solution per stage	Concentration in Frac Solution (ppm)	EPA Risk Based Concentration - Residential Tapwater (ppm)
	3	ICI-3240	Dazomet	24%	0.0000696	334000	61.42	
			Sodium Hydroxide	4%	0.0000116	334000	10.24	
		ICI-150	Glutaraldehyde	50%	0.00014125	334000	124.66	
			Methanol	5%	0.000014125	334000	12.47	18
		FRW-50	Diesel (use discontinued)	20%	0.000194	334000	171.21	
		FRW-25	no hazardous ingredients (used in place of FRW-50)	0%	0	334000	0.00	
Universal	1	Iron Check	no hazardous ingredients	0%	0	2000	0.00	
		HCl	Hydrochloric Acid	8%	0.0168896	2000	89.26	
	2	Unilink 8.5	Ethylene Glycol	40%	0.00111	42000	123.19	73
			Boric Acid	7%	0.00019425	42000	21.56	
		GBL-8x	n/a	0%	0	42000	0.00	
		Unigel 19XL	no hazardous ingredients (guar gum)	0%	0	42000	0.00	
	3	FRP-21	no hazardous ingredients	0%	0	334000	0.00	
		Bioclear 200	2,2-Dibromo-3-Nitripropionamide	20%	0.0000625	334000	55.16	
			Polyethylene Glycol Mixture	60%	0.0001875	334000	165.48	
Halliburton	1	HAI-OS	Methanol	60%	0.001068	2000	5.64	18
			Propargyl Alcohol	10%	0.000178	2000	0.94	0.073
		FE-1A	Acetic Acid	60%	0.001235042	2000	6.53	
			Acetic Anhydride	100%	0.002184454	2000	11.54	
		HCl	Hydrochloric Acid	8%	0.0168896	2000	89.26	
	2	K-34	Sodium Bicarbonate	100%	0.001271735	42000	141.13	
		BC 140	Monoethanolamine	30%	0.000523988	42000	58.15	
			Ethylene Glycol	30%	0.000566485	42000	62.87	73
			Boric Acid	30%	0.000608982	42000	67.58	
		Delta Frac 140	no hazardous ingredients	0%	0	42000	0.00	

SUMMARY OF HYDRAULIC FRACTURE SOLUTIONS - MARCELLUS SHALE								
Product Vendor	Application Sequence	Product Name	Hazardous Components (From MSDS)	Hazardous Ingredient Weight %	Pounds of hazardous ingredient / pound water	Gallons of Frac solution per stage	Concentration in Frac Solution (ppm)	EPA Risk Based Concentration - Residential Tapwater (ppm)
	3	FR-46	Ammonium Bisulfate	30%	0.000375	334000	330.95	
		Aldacide G	Glutaraldehyde	30%	0.0000798	334000	70.43	
Superior	1	AI-2	Glycol Ether (ethylene glycol monobutylether)	30%	0.000291	2000	1.54	18
			Propargyl Alcohol	30%	0.000291	2000	1.54	0.073
			Isopropyl Alcohol	30%	0.000291	2000	1.54	
			Proprietary Component	7%	0.0000679	2000	0.36	
		IC-100L	Cirtic Acid	100%	0.00154	2000	8.14	
		OB-Fe	Propylene Glycol	40%	0.000452	2000	2.39	730
			Ferrous Sulfate, Heptahydrate	30%	0.000339	2000	1.79	
		Super OW-3	Isopropyl Alcohol	40%	0.00018	2000	0.95	
			Methanol	13%	0.0000585	2000	0.31	10
		Super Pen 2000	Ethylhexanol	70%	0.000322	2000	1.70	
			Proprietary Component	30%	0.000138	2000	0.73	
		Super 100NE	Isopropyl Alcohol	30%	0.00015525	2000	0.82	
			Glycol Ethers	7%	0.00007245	2000	0.38	18
		HCl	Hydrochloric Acid	8%	0.0168896	2000	89.26	
	3	Bioclear 200	2,2-Dibromo-3-Nitrilopropionamide	20%	0.0000625	334000	55.16	
			Polyethylene Glycol Mixture	60%	0.0001875	334000	165.48	
		SAS-2	Hydrotreated Light Distillate	30%	0.000306	334000	270.06	
			Mineral Spirits	25%	0.000255	334000	225.05	
			Propylene Glycol	25%	0.000255	334000	225.05	730
			Ethoxylated Alcohols	4%	0.0000408	334000	36.01	

Regulatory Aspects ¹	NY	PA	AR	TX	LA
Regulation Name	Codes, Rules and Regulations of the State of New York, Title 6, Chapter V - Resource Management Services, Subchapter B: Mineral Resources, Parts 550 through 559	Pennsylvania Code, Title 25 (Environmental Protection), Chapters 78, 79, 91 (Oil & Gas Wells, Conservation, and Pollution Prevention)	Arkansas Code Annotated, Title 15, Subtitle 6, Chapter 72 (Oil and Gas Production), Subchapters 1 through 10	Texas Administrative Code, Title 16, Part 1, Chapter 3 (Oil and Gas Division), Rules 3.1 through 3.106	Louisiana Administrative Code, Title 43 (Natural Resources), Parts IX, XI, XIII, XV, XVII, IX
Regulation Code Name	6 NYCRR Parts 550 - 559	25 PA Code 78, 79, 91	15 ACA 72	16 TAC 3	43 LAC Parts 09, 11, 13, 15, 17, 19
URL of Regulation Website	http://www.dec.ny.gov/regs/2490.html	http://www.dep.state.pa.us/dep/deputate/minres/oilgas/laws&regulations.htm	http://www.arkleg.state.ar.us/SearchCenter/Pages/ArkansasCodeSearchResultPage.aspx	http://204.65.107.72/pls/pub/readtac\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y	http://www.doa.louisiana.gov/osr/lac/lac43.htm
Regulation pdfs	• 6_NYCRR_Parts550-559.pdf	• 25_PAC_78.pdf • 25_PAC_79.pdf • 25_PAC_91.pdf	• 15_ACA_72_Webpage.pdf • AROil&GasComm_2009_Regs.pdf	• 16_TAC_3.pdf	• 43_LAC_Part19.doc
Permit URL (also available in network folder)	http://www.dec.ny.gov/energy/1522.html	http://164.156.71.80/WXOD.aspx?fs=7780d840f80b00008000127900001279&ft=1	http://www.aogc.state.ar.us/aogcforms.htm	http://www.rrc.state.tx.us/licenses/og/index.php	• http://aogc.state.ar.us/aogcforms.htm • http://dnr.louisiana.gov/cons/CONSEREN/Permits/permitssection.ssi
Casing - Pollution prevention	<p>§554.1 Prevention of pollution and migration (a) The drilling, casing and completion program adopted for any well shall be such as to prevent pollution.</p>	<p>§ 78.81. General provisions. (a) The operator shall conduct casing and cementing activities under this section and § 78.82—78.87 or an approved alternate method under § 78.75 (relating to alternative methods). The operator shall case and cement a well to accomplish the following: (1) Allow effective control of the well at all times. (4) Prevent the migration of gas or other fluids into coal seams.</p>	No applicable regulations identified	<p>16 TAC §3.8 Water Protection (b) No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.</p>	No applicable regulations identified
Casing - Groundwater protection	<p>§554.1 Prevention of pollution and migration (b) Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited. (d) Except as hereinafter provided, sufficient surface casing shall be run in all wells to extend below the deepest potable fresh water level.</p> <p>Fresh Water Aquifer Supplementary Permit Conditions http://www.dec.ny.gov/energy/42714.html 5. A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. ... 6. If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office [NYDEC] may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone.</p> <p>Casing and Cementing Practices http://www.dec.ny.gov/energy/1757.html 2. Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper. However, the surface pipe must be set deeply enough to allow the BOP stack to contain any formation pressures that may be encountered before the next casing is run.</p>	<p>§ 78.81. General provisions. (a) The operator shall conduct casing and cementing activities under this section and § 78.82—78.87 or an approved alternate method under § 78.75 (relating to alternative methods). The operator shall case and cement a well to accomplish the following: (2) Prevent the migration of gas or other fluids into sources of fresh groundwater. (3) Prevent pollution or diminution of fresh groundwater. (b) The operator shall drill through fresh groundwater zones with diligence and as efficiently as practical to minimize drilling disturbance and commingling of groundwaters.</p> <p>Pennsylvania Act 223 Oil and Gas Sec. 601.207. Protection of fresh groundwater; casing requirements thereunder. (b) To prevent the migration of gas or fluids into sources of fresh groundwater and to prevent pollution or diminution of fresh groundwaters, there shall be run and permanently cemented a string or strings of casing in each well drilled through the fresh water bearing strata to a depth and in a manner prescribed by regulation by the department.</p>	<p>15-72-206.Casing oil or gas wells — Keeping sands separate. (a)The owner or operator of any well put down for the purpose of exploring for, or producing, oil or gas, shall, during the course of drilling, case off all fresh or salt water from each oil-producing or gas-producing sand encountered while drilling, the casing to be set in the well in such manner as to exclude all water from penetrating the first into a lower oil-bearing or gas-bearing sand, the well shall be cased in such manner as to exclude all fresh or salt water from all oil-bearing or gas-bearing sands encountered during the course of the drilling operations.</p>	<p>16 TAC §3.13 Casing, Cementing, Drilling, and Completion Requirements (a) General. (1) The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. (2) Definitions. The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise. (C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Texas Commission on Environmental Quality (TCEQ) or its successor agencies, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.</p>	<p>§109. Casing Program B. Surface Casing 1. Where no danger of pollution of fresh water sources exists, the minimum amount of surface of first-intermediate casing to be set shall be determined from Table 1 hereof. a.... If, however, in the opinion of the commissioner, or his agent, the above regulations shall be found inadequate, and additional or lesser amount of surface casing and/or cement or test pressure shall be required for the purpose of safety and the protection of fresh water sands.</p>

¹ Other aspects of state programs, including environmental policy processes, guidance, manuals, or permit conditions may establish additional requirements.

Regulatory Aspects ¹	NY	PA	AR	TX	LA
Casing - Cementing	<p>Casing and Cementing Practices http://www.dec.ny.gov/energy/1757.html Casing and Cementing Practices 6. Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. ... 7. The pump and plug method shall be used to cement surface casing. The amount of cement will be determined on a site specific basis and a minimum of 25% excess cement shall be used ... 9. The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement. 10. After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The WOC time shall be recorded on the drilling log. - When requested by the Department in writing, each operator must submit cement tickets and/or other documents that indicate the above specifications have been followed. The casing and cementing practices above are designed for typical surface casing cementing. The Department will require additional measures for wells drilled in environmentally or technically sensitive areas (i.e. primary or principal aquifers). Intermediate Casing ... Production Casing ... 15. The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.</p>	<p>§ 78.83. Surface and coal protective casing and cementing procedures. (c) If no fresh groundwater is being utilized as a source of drinking water within a 1,000- foot radius of the well, the operator may set and permanently cement a single string of surface casing through all water zones, including fresh, brackish and salt water zones. Prior to penetrating zones known to contain, or likely containing, oil or gas, the operator shall install and permanently cement the string of casing in a manner that segregates the various waters. (d) The operator shall permanently cement the surface casing by placing the cement in the casing and displacing it into the annular space between the wall of the hole and the outside of the casing. (e) Where potential oil or gas zones are anticipated to be found at depths within 50 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas. (f) If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall protect the additional fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the various zones. Sufficient cement shall be used to cement the casing at least 20 feet into the permanently cemented casing. (j) If it is anticipated that cement used to permanently cement the surface casing can not be circulated to the surface a cement basket may be installed immediately above the depth of the last circulation zone. The casing shall be permanently cemented by the § 78.85. Cement standards.</p>	<p>Rule B-15 - Casing requirements b. All fresh water sands shall be fully protected by the setting and cementing of surface casing to prevent the fresh water sands from becoming contaminated with oil, gas, or salt water. Surface casing shall be set and cement circulated to surface utilizing the pump and plug method. Cement shall be allowed to set a minimum of twelve (12) hours. c. A producing string of casing shall be set at least to the top of the producing formation and shall be cemented so that the calculated fill, after allowing for twenty-five percent excess, will be at least two hundred fifty feet above the top of any productive interval. Cementing shall be done by the pump and plug method. Cement shall be allowed to set a minimum of twenty-four (24) hours before drilling the plug.</p>	<p>16 TAC §3.13 Casing, Cementing, Drilling, and Completion Requirements (b) Onshore and inland waters. (2) Surface casing. (A) Amount required. (i) An operator shall use a quality cement slurry sufficient to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or his representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface. (C) Cement quality. ... (D) Compressive strength tests. ... (E) Cementing report. ... (3) Intermediate casing. (A) Cementing method. ... (4) Production casing. (A) Cementing method. ...</p>	<p>§109. Casing Program B. Surface Casing 3. Cement shall be allowed to stand a minimum of 12 hours under pressure before initiating test or drilling plug. Under pressure is complied with if one float valve is used or if pressure is held otherwise. C. Intermediate Casing 2. If an intermediate casing string is deemed necessary by the district manager for the prevention of underground waste, such regulations pertaining to a minimum setting depth, quality of casing, and cementing and testing of sand, shall be determined by the department after due hearing. The provisions of Paragraph D.7 below, for the producing casing, shall also apply to the intermediate casing. D. Producing Oil String 3. Cement shall be by the pump-and-plug method, or another method approved by the department. ... 5. Cement shall be allowed to stand a minimum of 12 hours under pressure and a minimum total of 24 hours before initiating test or drill plug in the producing or oil string. ...</p>
Testing well seals (Mechanical Integrity Testing (MIT))	No applicable regulations identified	<p>§ 78.103. Annual monitoring of inactive wells. The owner or operator of a well granted inactive status shall monitor the integrity of the well on an annual basis and shall report the results to the Department. The owner or operator shall give the Department 3 working days prior notice of the annual monitoring and mechanical integrity testing. ...</p>	No applicable regulations identified	<p>16 TAC §3.13 Casing, Cementing, Drilling, and Completion Requirements (b) Onshore and inland waters. (1) General. (D) When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.</p>	<p>§109. Casing Program B. Surface Casing 2. Surface casing shall be tested before drilling the plug by applying a minimum pump pressure as set forth in Table 1 after at least 200 feet of the mud-laden fluid has been displaced with water at the top of the column. If at the end of 30 minutes the pressure gauge shows a drop of 10 percent of test pressure as outlined in Table 1, the operator shall be required to take such corrective measures as will insure that such surface casing will hold said pressure for 30 minutes without a drop of more than 10 percent of the test pressure. The provisions of Paragraph D.7, below, for the producing casing, shall also apply to the surface casing.</p>

¹ Other aspects of state programs, including environmental policy processes, guidance, manuals, or permit conditions may establish additional requirements.

Regulatory Aspects ¹	NY	PA	AR	TX	LA
Disclosure of drilling/fracking fluid and additive constituents	<p>Well Drilling and Completion Report, Stimulation Data Details: type and volume of materials</p>	<p>Drilling companies must disclose the names of all chemicals to be stored and used at a drilling site in the Pollution Prevention and Contingency Plan that must be submitted to DEP as part of the permit application process. These plans contain copies of material safety data sheets for all chemicals, and DEP recommends to operators that a copy be kept on each well site. This information is on file with DEP and is available to landowners, local governments and emergency responders.</p>	<p>No applicable regulations identified</p>	<p>No applicable regulations identified</p>	<p>33 LAC V:101 Hazardous Material Information Development, Preparedness, and Response Act §10101. Declaration of Authority, Background, Policy and Purpose B. This Act was originally passed as Act 435 of the 1985 Legislative Session to implement the state's first "Right-to-Know" law. §10109. Inventory Reporting B. Any material for which a facility must prepare or maintain a Material Safety Data Sheet (MSDS) under the Occupational Safety and Health Administration (OSHA) Hazard Communication Standard (as listed in 29 CFR 1910.1200 et seq.) must be reported ... must be reported ... if the material is present at a facility in threshold (inventory) quantities (TQ) of 500 pounds or more on any single day.</p>
Completion reports	<p>§554.7 Completion reports, well logs and samples (a) Within 30 days after the completion of any well, a completion report utilizing form OG10 shall be filed in triplicate by the owner or operator with the department summarizing thereon the completion details. (b) Each copy of the completion report on form OG10 also shall be accompanied by a well log and such other information as the department may specifically require. The measurement datum for the well log and all other measurements in connection with the well shall be clearly specified. The well log also must show the elevation in feet of the measurement datum with respect to mean sea level.</p>	<p>§ 78.122. Well record and completion report. (a) For each well that is drilled or altered, the operator shall keep a detailed drillers log at the well site available for inspection until drilling is completed. Within 30 calendar days of cessation of drilling or altering a well, the well operator shall submit a well record to the Department on a form provided by the Department that includes the following information: (6) Size and depth of conductor pipe, surface casing, coal protective casing, production casing and borehole. (7) Type and amount of cement and results of cementing procedures. (8) Elevation and total depth. (9) Drillers log that includes the name and depth of formations from the surface to total depth, depth of oil and gas producing zone, depth of fresh water and brines and source of information. (10) Other information required by the Department. (b) Within 30 calendar days after completion of the well, the well operator shall submit a completion report to the Department on a form provided by the Department that includes the following information: (5) Perforation record. (6) Stimulation record. (7) Actual open flow production and rock pressure. (8) Open flow production and rock pressure, measured 24 hours after treatment.</p>	<p>Rule B-5 - Submission of well records and issuance of certificate of compliance f. Upon original completion or recompletion of the well, the operator, contractor, driller, or other person responsible for the conduct of the drilling operation shall file with the Commission: 1. Properly filled out Well Completion Report.</p>	<p>16 TAC §3.16 Log and Completion or Plugging Report (b) Completion and plugging reports. The operator of a well shall file with the commission the appropriate completion report within 30 days after completion of the well or within 90 days after the date on which the drilling operation is completed, whichever is earlier. (c) Basic electric logs. Except as otherwise provided in this section, not later than the 90th day after the date a drilling operation is completed, the operator shall file with the commission a legible and unaltered copy of a basic electric log, ...</p>	<p>§107. Records D. A new form entitled "Well History and Work Résumé Report" (Form WH) shall be filed with the district office in which the well is located within 20 days after completion of the well. §119. Well Allowables and Completion A. New Well and Recompleted Well Allowables 1. Upon completion or recompletion of a well, immediate notice within 24 hours from the time of completion (Sundays and holidays excepted) must be filed in writing with the district office on forms provided by the department.</p>
Additional logs and data	<p>No applicable regulations identified</p>	<p>§ 78.123. Logs and additional data. (a) If requested by the Department within 90 calendar days after the completion of drilling or recompletion of a well, the well operator shall submit to the Department a copy of the electrical, radioactive or other standard industry logs run on the well. In addition, if requested by the Department within 1 year of the completion of drilling or recompletion of a well, the well operator shall file with the Department a copy of the drill stem test charts, formation water analysis, porosity, permeability or fluid saturation measurements, core analysis and lithologic log or sample description or other similar data as compiled. No information will be required unless the operator has had the information described in this subsection compiled in the ordinary course of business. No interpretation of the data is to be filed. (b) Upon notification by the Department prior to drilling, the well operator shall collect additional data specified by the Department, such as representative drill cuttings and samples from cores taken, and other geological information that the operator can reasonably compile.</p>	<p>Rule B-5 - Submission of well records and issuance of certificate of compliance f. Upon original completion or recompletion of the well, the operator, contractor, driller, or other person responsible for the conduct of the drilling operation shall file with the Commission: 2. All electric logs or other geophysical logs of the open well bore, which measure resistivity, porosity, temperature, and gamma ray emission and for planned directional and horizontal wells, borehole deviation and direction logs including a true vertical depth logs ...</p>	<p>16 TAC §3.16 Log and Completion or Plugging Report ((c) Basic electric logs. Except as otherwise provided in this section, not later than the 90th day after the date a drilling operation is completed, the operator shall file with the commission a legible and unaltered copy of a basic electric log, ...</p>	<p>§107. Records B. Electrical logs, when run, of all test wells, or wells drilled in search of oil, gas, sulphur and other minerals, shall be mailed in duplicate to the district office of the Department of Conservation</p>

¹ Other aspects of state programs, including environmental policy processes, guidance, manuals, or permit conditions may establish additional requirements.

Regulatory Aspects ¹	NY	PA	AR	TX	LA
Hydraulic fracturing	<p>Fresh Water Aquifer Supplementary Permit Conditions http://www.dec.ny.gov/energy/42714.html 8. This office [NYDEC] must be notified (to be determined by DEC on individual well basis) hours prior to any stimulation operation. Stimulation may commence without the state inspector if the inspector is not on location at the time specified during the notification.</p> <p>Well Drilling and Completion Report, Stimulation Data Zones Treated: Upper and lower depths Details: type and volume of materials, rates, breakdown psi, average treatment psi, isip, etc.</p>	<p>§ 78.122. Well record and completion report. ((b) Within 30 calendar days after completion of the well, the well operator shall submit a completion report to the Department on a form provided by the Department that includes the following information: (6) Stimulation record.</p> <p>§ 78.903. Frequency of inspections. The Department, its employes and agents intend to conduct inspections at the following frequencies: (3) At least once during each of the phases of siting, drilling, casing, cementing, completing, altering and stimulating a well.</p>	<p>No applicable regulations identified</p>	<p>No applicable regulations identified</p>	<p>§105. All Other Applications A. All applications for permits to repair (except ordinary maintenance operations), abandon (plug and abandon), acidize, deepen, perforate, perforate and squeeze, plug (plug back), plug and perforate, plug back and side-track, plug and squeeze, pull casing, side-track, squeeze, squeeze and perforate, workover, cement casing or liner as workover feature, or when a well is to be killed or directionally drilled, shall be made to the district office on Form MD-11-R and a proper permit shall be received from the district manager before work is started.</p>

¹ Other aspects of state programs, including environmental policy processes, guidance, manuals, or permit conditions may establish additional requirements.