A POLICY AND IMPACT ANALYSIS OF HYDRAULIC FRACTURING IN THE MARCELLUS SHALE REGION: A WILDLIFE PERSPECTIVE

by

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ABSTRACT

Hydraulic fracturing for natural gas in the Marcellus Shale (underlying about 24 mil ha in New York, Pennsylvania, Maryland, West Virginia, Ohio, and Virginia) has become a politically charged issue, primarily because of concerns about drinking water safety and human health. This thesis examines hydraulic fracturing in the Marcellus Shale region using an E3 analysis; looking at the energy potential of the natural gas in the basin, the economics of shale gas extraction, and the environmental impact from a wildlife perspective. The thesis also examines the federal, regional, and state policies and regulations that apply to the industry.

The Marcellus Shale has the most technically recoverable gas of any basin in the United States at 141 trillion cubic feet. Based on current U.S. consumption, the Marcellus could provide all the natural gas used in the country for 5.5 years.

Income from natural gas development comes primarily from jobs (direct such as gas workers, indirect such as equipment suppliers, and induced jobs which are created when direct workers spend their earnings in a community) and taxes and fees.

From a wildlife perspective, environmental effects are primarily on habitat. Terrestrial habitat effects are primarily due to landscape fragmentation from clearing of land for well pad development, which removes mature forest and creates edge habitat. An increase in forest edges is associated with an increase in nest predation and brood parasitism, which could put edge-nesting songbird species at risk. Aquatic habitat effects

are less well understood. Hydraulic fracturing requires up to 19 mil l of water per well fracture and in the Marcellus Shale region, most of that comes from surface water sources. Removal of water from surface water sources can increase sedimentation, alter the temperature, and change the chemistry of the water, resulting in changes in the biodiversity of the water source.

Federal oversight of natural gas production is managed through a variety of regulations, primarily the National Environmental Protection Act, the Clean Water Act (although hydraulic fracturing was exempted from the erosion control provisions via the Energy Policy Act of 2005), the Clean Air Act, the Endangered Species Act, the Mineral Leasing Act, the Natural Gas Act, and several others. The Susquehanna River Basin Commission and the Delaware River Basin Commission (DRBC) regulate water usage in their respective watersheds, although the DRBC has yet to finalize the regulations for water usage for hydraulic fracturing in the Delaware River Basin. Each of the states in the region regulate the industry in different ways.

Given that hydraulic fracturing will continue, further research is needed on habitat impacts, especially on aquatic habitats. Best Management Practices need to be agreed upon by stakeholders (industry, regulators, non-governmental organizations). Federal regulation is required to force operators to consistently disclose the chemicals used in the fracturing fluid and to mandate erosion/sediment control. An Ohio River Basin Commission needs to be chartered to manage water use in the Ohio River Basin, as it is in the Susquehanna and Delaware River basins. States need to actively manage reclamation activities to ensure native plantings.

Chapter 1

INTRODUCTION

Hydraulic fracturing for natural gas (also known as “fracking”) is a highly politically charged topic. Proponents point to the potential of the technique to produce enough natural gas within the United States to reduce the country’s dependence on imported natural gas. Opponents are concerned about the potential environmental effects of fracking. There are valid arguments to be made on both sides of the issue, but the debate is anthropocentric. Only humans use natural gas and, for the most part, those protesting fracking’s environmental impacts are primarily concerned about human health (e.g. drinking water quality).

This thesis examines fracking from a wildlife perspective, with particular emphasis on the impacts to wildlife habitats in the Marcellus Shale region in the northeastern United States. I will describe the technology itself and review the applicable legislation and regulations at the federal, regional, state, and local levels. In order to fully understand natural gas development policy and impacts, we must review it from 3 different dimensions, collectively called an E3 analysis:

1. Energy potential – i.e. how much gas is there and how does it impact the overall natural gas resource in the United States?
2. Economics – i.e. what are the costs and the benefits nationally and locally?
3. Environmental impacts - i.e. what does this type of development do to the wildlife habitats in the region?

Looking at all 3 of these dimensions allows us to understand the points of view of all the stakeholders involved, including industry, regulators, and wildlife managers.

Aldo Leopold (1949) posed the question of "whether a still higher 'standard of living' is worth its cost in things natural, wild, and free." While every stakeholder will have their own answer to that question, in this thesis I try to provide the information to answer it as objectively as possible.

Chapter 2

TECHNOLOGY DESCRIPTION/HISTORY

Shale gas

Shale is formed over geologic time when layers of sediment compact under heat and pressure into rock with low horizontal permeability and even lower vertical permeability (Boyer et al. 2006, Arthur et al. 2008*a*). Gas is formed in the shale when organic material trapped between the layers decomposes anaerobically (Kargbo et al. 2010). Shale gas is typically at least 90% methane along with small percentages of other volatile organic compounds such as butane, propane, and ethane (United States Department of Energy [USDOE] 2009, Jackson et al. 2011). Since shale gas forms in place, the shale is considered both a source rock and a reservoir (Boyer et al. 2006). Since the rock is nearly impermeable, the gas is trapped in the porosity of the rock and does not easily migrate between rock layers (USDOE 2009).

Because the gas is trapped, it cannot be easily extracted without increasing the rock's permeability (Arthur et al. 2008*a*). Because of this low permeability, shale gas formations are considered unconventional gas reservoirs, in contrast to conventional reservoirs in porous substrates that allow the gas to flow freely within the formation (USDOE 2009). Because conventional drilling techniques have not been economical or efficient to mine unconventional gas "plays" (USDOE 2009, Jackson et al. 2011), this resource had largely been unavailable until more advanced drilling technologies were developed.

Shale gas basins occur across much of the United States (Figure 2-1). The most developed of these shale gas plays is the Barnett in north-central Texas. At 1.3 mil ha, it is not the largest, but it was the nation's highest producing shale play until early 2011, when it was surpassed by the Haynesville play in Louisiana (United States Energy Information Administration [USEIA] 2011). In the Barnett, the shale layer is approximately 2.0–2.6 km below the surface and is 30–180 m thick (USDOE 2009). It is the most concentrated of all the U. S. gas plays, with 300–350 standard cubic feet of gas/ton (USDOE 2009). Beginning in the 1980s hydraulic fracturing and horizontal drilling (see descriptions below) were developed and employed in the Barnett, which today hosts >10,000 wells (USDOE 2009).

The largest shale formation in North America is the Bakken formation in North Dakota and Montana in the United States and Saskatchewan and Manitoba in Canada. The Bakken formation to date has primarily yielded oil, although some limited natural gas drilling has occurred there (United States Geological Survey [USGS] 2008). The next largest is the Utica Shale formation that underlies New York, Pennsylvania, Maryland, West Virginia, Ohio, and Virginia, and extends north under Lake Ontario, and northwest under Lake Erie and Ontario, Canada. It covers an area of approximately 44 mil ha (Ryder 2008). It is an Ordovician-age formation and ranges in depth from 600 m at its western edge to over 3600 m in northeastern Pennsylvania and varies in thickness from 30–150 m. The energy potential in the Utica Shale is currently estimated at 16 trillion cubic feet (tcf) (USEIA 2012*a*). Overlying the Utica Shale formation is the Marcellus shale basin, covering an area of about 24.6 mil ha in New York, Pennsylvania, Maryland, West Virginia, Ohio, and Virginia (USDOE 2009). It is a Devonian-age shale formation, deposited in a continental seaway with little fresh water sedimentation (Arthur et al. 2008*a*). It is ≤60 m thick, lying at a depth of 1200–2600 m (USDOE 2009). Because of this formation's more shallow depth, gas collection is more feasible and the United States Energy Information Administration estimates that it contains up to 1500 tcf of gas-in-place, with technically recoverable resources of 141 tcf – the most of any shale basin in the United States (USEIA 2012*a*).

Preliminary Surveys

To determine the best places to drill, gas companies usually perform seismic testing. Seismic waves are artificially created through vibrations at or near the surface and picked up by receiving devices known as geophones. Because different rock densities transmit the vibrations differently, geologists can determine the properties of the underground layers and pinpoint the location of gas deposits (Natural Gas Supply Association 2013). Either explosives or vibroseis trucks (colloquially known as "vibe" or "thumper" trucks) create the seismic waves.

If explosives are the source of vibration, the testing company must drill 6–30 m deep "shot-holes" in linear patterns throughout the testing area, into which explosives are placed (Langlois 2012). The land may be cleared in preparation for drilling of shot-holes to allow access by the drilling equipment. The cleared areas are generally only a few meters wide, but extend the entire length of the explosive line. Some gas companies minimize the clearing by using smaller equipment that can travel through brush and around trees. If the target area is not accessible by land, the equipment and crew are flown in by helicopter to drill the shot-holes and place the charges.

Vibroseis trucks are large (>22.5 metric tons) and can only be used on roads. Each truck is equipped with a large hydraulically controlled plate, which is lowered to the ground to create low-energy vibrations. Three or four trucks are synchronized to create simultaneous vibrations. Geophones are placed in a linear pattern (similar to that used for explosive vibrations) to pick up the waves created by the vibrations.

Shale drilling process

Traditionally, natural gas in conventional formations has been extracted using vertical wells. These wells are drilled to depths of ≤6400 m to tap into a gas reservoir (PIOGA 2012). Wells are lined with a series of steel casings with the space between the casings and the surrounding rock filled with cement to isolate the well from underground drinking water sources (UDWS). The casings are installed to a depth beneath that of any UDWS, to protect the source from chemical contamination from the well. To extract gas from a vertical well, it may be necessary for the well to be fractured with explosives and/or injected with a few thousand gallons of water, sand, and chemicals under extremely high pressure to open fissures in the rock and encourage the flow of gas.

Hydraulic fracturing

Because shale gas is trapped in the rock and doesn't generally form in large, more easily accessible reservoirs, traditional vertical drilling is not very effective. Two newer technologies have been combined to efficiently and economically mine shale gas plays: horizontal drilling and hydraulic fracturing. The development of horizontal drilling techniques has been key to the development of shale gas resources. Horizontal drilling has reduced the cost of drilling, as multiple horizontal wells can be drilled from one pad and drilling horizontally allows the well to be placed between the layers of rock, thereby creating exposure to more interstitial gas at lower cost (Boyer et al. 2006, USDOE 2009).

As importantly, hydraulic fracturing has been introduced as a technology to extract this traditionally inaccessible resource. To extract natural gas from shale, either a vertical or horizontal well is drilled (Figure 2-2) to a depth of about 1800 m (USDOE 2009). As for vertical wells, the upper sections of the well are also lined with a series of casings embedded in cement to seal the well off from UDWS. Once the well drilling and lining are complete, the gas is extracted via a process known as hydraulic fracturing (hereafter fracking). The casings in the horizontal portion of the well are perforated via explosives placed at intervals in the target area to allow fracturing liquids to enter the shale. Fracking is a multi-step process, beginning with the injection of a 15% hydrochloric (muriatic) acid solution to remove drilling mud and cement from the interior of the upper portion of the well (USDOE 2009). In the second step, water mixed with polyacrylamide or mineral oil is injected into the well to reduce friction. This allows subsequent fluid injections to travel more freely into the shale formation. Following this step, the fracturing liquids are injected into the well at high pressure (approximately 10,000 psi) to force the fluid into the shale (Hanlon 2011).

Fracturing liquids contain a variety of chemicals and sand (Table 2-1), which acts as a proppant to keep the fissures in the shale open during extraction (USDOE 2009). The exact chemical composition of the fracturing fluid is generally considered proprietary, but operators are recently more frequently disclosing the contents of the fluid in FracFocus.org, a publicly accessible database. In addition to the proppant and the hydrochloric acid, common components listed in a random sample of 762 documents from FracFocus downloaded in February 2012 (out of approximately 7600 documents in the database at that time) include surfactants such as ethanol, butoxyethanol, and naphthalene, potassium carbonate and sodium hydroxide to adjust the pH of the fluid, and proprietary paraffinic solvents to reduce friction in the well. Gelling and cross-linking agents such as guar gum and potassium hydroxide are used to enhance the carrier fluid's capability to advance the proppant into the crevices. Sodium persulfate, ammonium persulfate, or chlorous acid are then commonly used as "breakers" to break down the gelled fluid to make it easier to extract from the well. Isopropanol, formic acid, and other formamides are used as corrosion inhibitors. Biocides such as glutaraldehyde are used to prevent microbial growth in the fracturing fluid.

The random sample of 762 included 109 documents from the Marcellus Region. The chemicals disclosed in those documents are similar to those disclosed overall. A comparison between the percentage of Marcellus wells where common chemicals were used and the percentage of wells overall is presented in Table 2-1.

When the pumping stops, the fluid and natural gas begin to flow back. Approximately 1/3 of the injected fluids will flow back through the wellhead, while the rest of the fluid remains trapped in the shale formation (Hanlon 2011). The flowback water is collected and either stored for re-use or treated as wastewater.

Re-fracking

Wells can be and often are fractured multiple times; the exact number of fracturing efforts is dependent on the gas available and the geologic conditions of the well. Refracturing of the well takes about the same amount of water as the initial fracturing effort. Non-producing wells can be capped for an indeterminate amount of time for later re-fracking.

Water Supply

Drilling and fracking a single well takes several weeks to complete and requires between 7–19 mil L of water, although this varies considerably with the depth and diameter of the well, and the length of the horizontal portion (USDOE 2009). Between 303,000 L and 3.3 mil L of water is required for the actual drilling operation, with the remaining being used during the fracturing process. This water is obtained from surface sources (including lakes and rivers), groundwater, or municipal supplies, with increasing amounts coming more recently from re-used fracturing liquid.

Availability of water varies between regions and can vary seasonally and during drought conditions within a region. Surface water is in short supply in areas such as the Barnett Shale region in north-central Texas, while it is generally more available in the northeastern United States. If sufficient surface water or groundwater exists in close proximity to the well pad, water is pumped from the source and piped or trucked to the well pad (Soeder and Kappel 2009). When local water supplies are low, water is trucked in from more distant locations. If surface water or groundwater is not available, municipally supplied water is generally trucked to the well pad. Some companies build freshwater storage impoundments at the well pad and fill them when water supplies are sufficient for use during times of insufficient supply (USDOE 2009).

Increasingly, operators are re-using flowback liquid as the fracturing liquid. This allows them to reduce the volume of fresh water required for fracturing and refracturing a well. Treatment of the flowback liquid is required prior to reuse to prevent downhole scaling or the buildup of sediment in the well from the flowback liquid. Reusing the fluid requires that it be stored at the well pad in tanks or impoundments until needed for refracturing or transported to other sites as needed.

Freshwater from surface sources such as lakes and rivers makes up about 0.266% of all freshwater available on earth and only about 0.007% of all water on earth (Shiklomanov 1993). Drilling and fracturing a single horizontal well in the Marcellus region can require up to 19 million L of water. Withdrawal of fresh water for this purpose is considered a consumptive use, since only a small percentage of the water is returned to the water cycle and is thereafter available for other uses (Figure 2-3). Most of the water (up to 70%) used in natural gas production remains deep underground in the well it was used to drill or fracture. The rest of the water is either disposed of in underground injection wells or treated as wastewater and released back to surface water sources. It is only the water that is treated and released that is ever available again to the water cycle.

In the Marcellus region, where surface water is relatively plentiful compared to the deserts of the American southwest, much of the water used is obtained from surface sources. For example, from mid-2008 through mid-2010 in the Susquehanna River Basin, 71% of the water used for drilling and fracturing natural gas wells came from surface water sources (Susquehanna River Basin Commission [SRBC] 2010). In West Virginia between 2010–2012, approximately 664 wells were drilled (Table 2-2). At an average of 19 million L of water each, it required a total of over 12.6 billion L to drill and fracture those wells, of which over 10 billion L (81%) came from surface water sources, an average of 9.3 million L/day (Hansen et al. 2013). In Pennsylvania, approximately 4615 wells were drilled in that same time period (Pennsylvania Department of Environmental Protection [PA DEP] 2014). Assuming an average of 19 million L of water is required to drill and fracture each of those wells, a total of approximately 87.7 billion L was required, of which approximately 62.3 billion L (71%) would have been withdrawn from surface fresh water sources, an average of about 57 million L/day. In 2013, the number of wells drilled dropped to 1167 (PA DEP 2014), which required approximately 22.2 billion L to drill and fracture, 15.7 billion L of which would have come from surface water sources. These estimates include only a single fracture of a well; most producing wells are fractured multiple times during the productive period. Each subsequent fracture uses an additional 15 to 19 million L of water.

To put these hydraulic fracturing water use estimates into perspective, more surface water is used in the generation of thermoelectric power in the United States than for any other purpose (USGS 2005). In West Virginia, 3.6 billion L/day were withdrawn from surface freshwater sources for thermoelectric power generation in 2005 (USGS 2005), equal to the average annual freshwater usage for natural gas extraction. In Pennsylvania, 6.4 billion L/day were withdrawn from surface freshwater sources for thermoelectric power generation in 2005 (USGS 2005). The average annual freshwater withdrawal for natural gas extraction in Pennsylvania from 2010–2012 is equivalent to approximately 3.28 days of freshwater usage for thermoelectric power (57 mill L/day *365 = 20,805,000,000 l/yr for natural gas approx = 6.4 bill L/day *3.28 days). While the volume of water withdrawn for thermoelectric power is orders of magnitude greater than for shale gas extraction, the water used is returned to the water cycle. Most of the water is returned directly to a surface water source, while the remainder evaporates or leaks from the thermoelectric system.

Well pad and vicinity construction

The minimum drainage area of a well pad is determined by state and provincial regulations and currently ranges from 16 ha for a vertical well to 65 ha for a horizontal well (Arthur et al. 2008*a*). Of this, 1–3.6 ha are usually cleared for construction of the wellhead and supporting structures such as fluid storage tanks or evaporation pits (U. S. National Park Service 2009). Producers must also build roads to the well pad and upgrade existing roads to handle the heavy truck traffic. In areas of higher well density, separate areas may be cleared to provide sites for freshwater impoundments. These impoundments can be 500 acre-feet or more thus requiring a large cleared area (Arthur et al. 2008*b*).

In addition to freshwater and flowback water storage, operators need room to store large equipment. If a non-operating wellpad is available in the area, many companies will reuse those sites for equipment storage, but if not, additional area may be cleared to provide locations for storage.

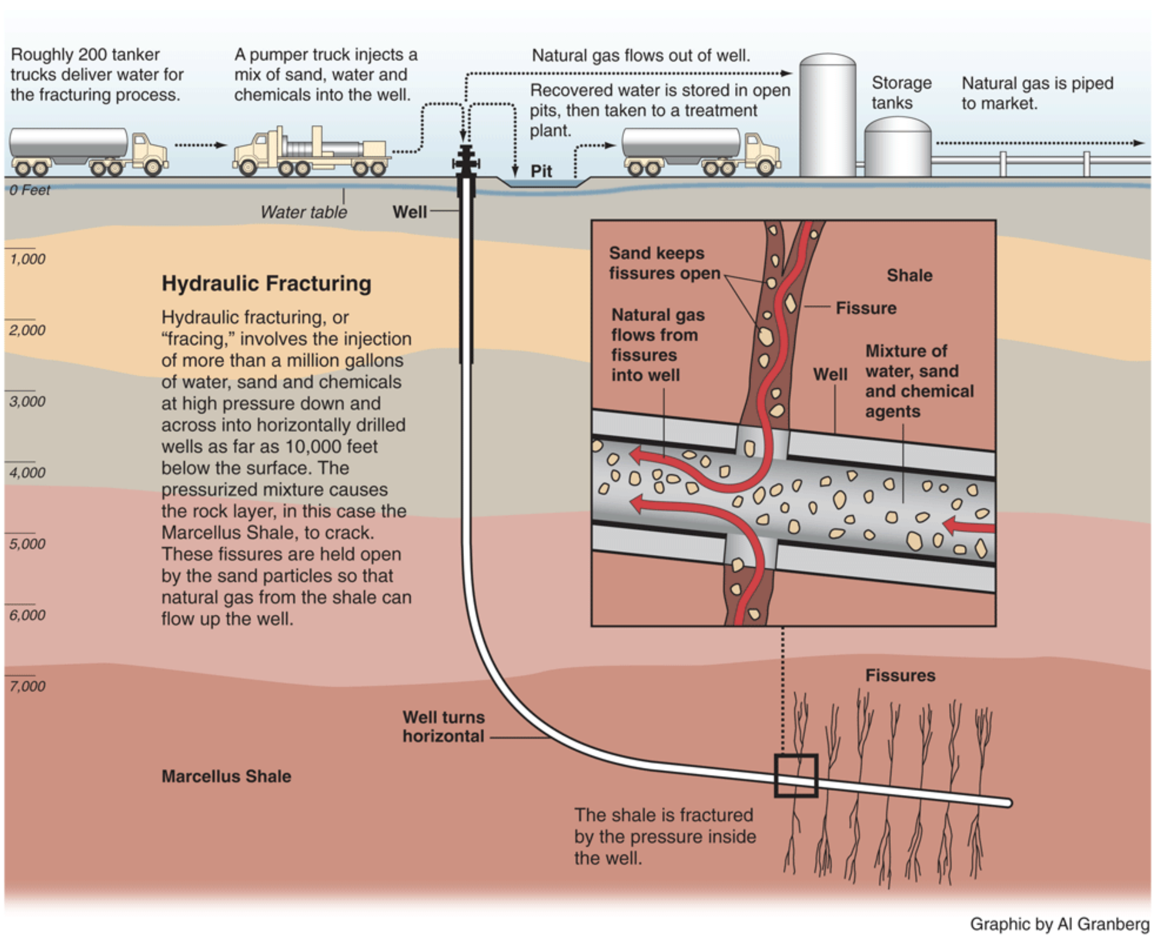
Natural gas is transported through an extensive network of pipelines that transect the United States and Canada. Smaller diameter gathering pipelines from the well pad are built to transport the gas to the nearest large-diameter, pressurized transfer pipelines. The highest density of existing pipelines corresponds to the longest operating and largest gas plays in Texas (Figure 2-4). The existing pipeline network is currently much more extensive in the western region of the Marcellus basin than in the eastern portion. With development in the eastern Marcellus region increasing, however, more pipelines will be constructed to accommodate the increased production. In Pennsylvania, an estimated 16,000–40,000 k of new pipeline will be necessary to support the projected number of new wells by 2030 (Johnson et al. 2010). This pipeline, along with the other associated infrastructure for a well (roads, impoundments, etc), requires an average of 5.7 acres of cleared land per well (Johnson et al. 2010). Natural gas pipelines require compressor stations to maintain pressure within the pipeline and when additional pipelines are constructed, new compressor stations are also needed (USDOE 2009).

Construction may also be required to house gas company workers. In some areas, existing housing cannot accommodate the influx of workers, particularly during the construction phase. Additional land may be cleared to build housing for workers, as in Athens, Pennsylvania, where a facility to house and train 280 workers was built by the Chesapeake Energy Corporation on 5.3 ha of previously undeveloped land (Marshall 2010).

Figure 2-1 North American shale plays

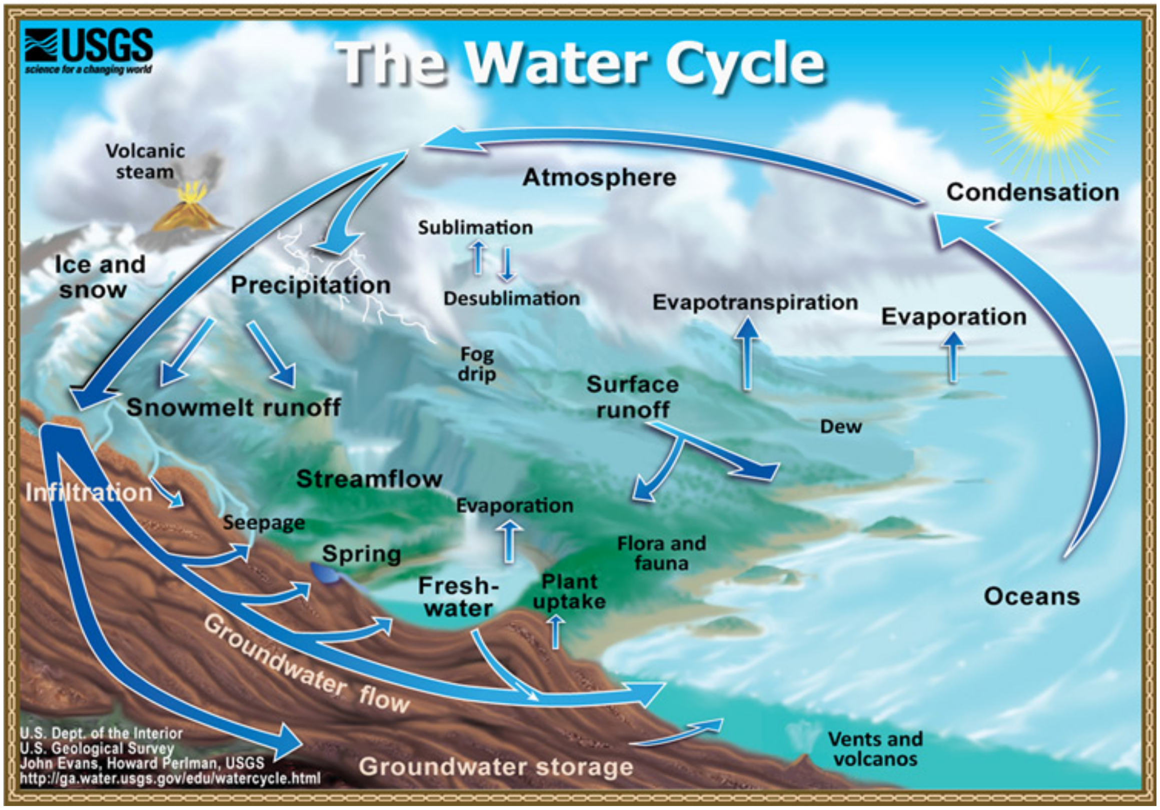
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Figure 2-2 Hydraulic fracturing



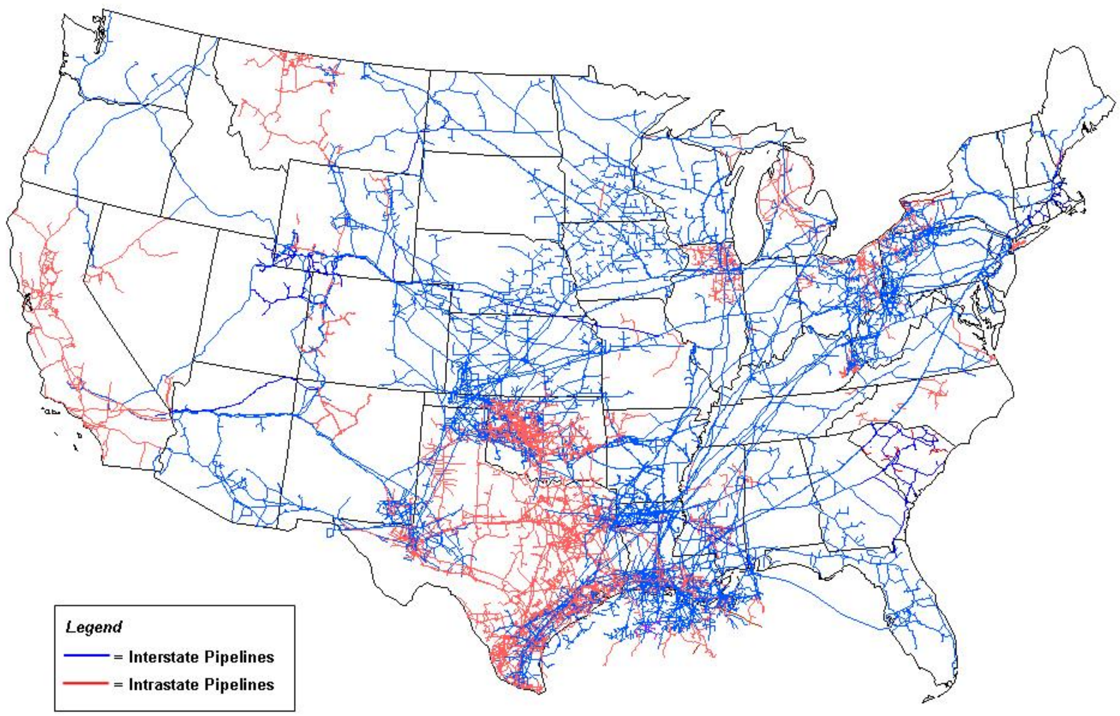
Source: http://www.propublica.org/special/hydraulic-fracturing-national

Figure 2-3 The water cycle



Source: United States Geological Survey
(http://ga.water.usgs.gov/edu/watercyclehi.html)

Figure 2-4 Natural gas pipelines in the United States



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

Table 2-1. Common components of hydraulic fracturing fluids as disclosed in FracFocus[1]

Component	Purpose	Chemical Abstract Service (CAS) Number	Overall % Wells Using	Marcellus Shale % Using
Sand	Proppant	N/A	90.0	79.8
Silica quartz	Proppant	14808-60-7	78.6	46.8
Methanol	Corrosion inhibitor/winterizing agent/friction reducer/ gelling agent	67-56-1	75.7	74.3
Hydrochloric (muriatic) acid	Acid - dissolves minerals	7647-01-0	71.9	95.4
Petroleum distillate	Carrier fluid/gelling agent	64742-47-8	71.9	64.2
Water	Carrier/base fluid	7732-18-5	59.3	37.6
Isopropanol	Corrosion inhibitor	67-63-0	49.5	30.3
Ethanol	Surfactant/Biocide/ Proppant transport	64-17-5	40.3	25.7
Propargyl alcohol	Corrosion inhibitor	107-19-7	34.0	50.5
Sodium hydroxide	pH	1310-73-2	32.4	8.3
Glutaraldehyde	Biocide	111-30-8	31.4	32.1
Ammonium persulfate	Breaker	7727-54-0	27.8	8.3
Ethylene glycol	Stabilizer/winterizing agent/friction reducer/ gelling agent	107-21-1	27.2	35.8
Sodium chloride	Stabilizer/breaker	6747-14-5	24.1	0.0
Citric acid	Iron control	77-92-9	23.6	36.7
2-butoxyethanol	Surfactant	111-76-2	20.9	16.5
Naphthalene	Surfactant	91-20-3	20.5	3.7
guar gum	Gelling agent	9000-30-0	19.9	16.5
Potassium hydroxide	Crosslinker	1310-58-3	18.8	2.8
Chlorous acid	Breaker	7758-19-2	15.2	4.6
Choline chloride	Clay stabilizer	67-48-1	14.3	0.0
Potassium carbonate	pH	584-08-7	12.9	9.2
Sodium persulfate	Breaker	7775-27-1	12.2	19.3

Table 2-1 continued

Component	Purpose	Chemical Abstract Service (CAS) Number	Overall % Wells Using	Marcellus Shale % Using
Formamide/N,n-dimethyl formamide	Corrosion inhibitor	75-12-7/ 68-12-2	10.8	15.6
Formic acid	Corrosion inhibitor	64-18-6	10.8	5.5
Sodium erythorbate	Iron control	6381-77-7	9.4	6.4
Didecyl dimethyl ammonium chloride	Biocide	7173-51-5	8.8	11.0
Naphtha	Gelling agent	64742-48-9	8.0	11.0
Terpenese/Terpenoides	Surfactant	68647-72-3	7.9	1.8
Paraffinic solvent	Friction reducer	Proprietary	7.5	9.2
Polyacrylate	Scale inhibitor	Not listed	6.3	0.0
Potassium metaborate	Crosslinker/pH adjuster	13709-94-9	6.2	0.0
Tetramethylammonium chloride	Clay stabilizer	75-57-0	5.8	0.0
Sodium tetraborate	Maintains viscosity	1330-43-4	5.6	0.0
Phenol	Proppant	900303-35-4	5.1	0.0
Diethylene glycol	Scale inhibitor/Biocide/ Foaming agent	111-46-6	5.0	10.1
Borate salts	Maintains viscosity	Confidential business info	4.9	0.0
Hemicellulase enzyme	Breaker	9012-54-8	3.5	16.5
Mullite	Proppant	1302-93-8	3.5	0.0
Potassium formate	Crosslinker	590-29-4	2.5	0.0
Kerosene	Corrosion inhibitor	8008-20-6	2.2	2.8
Corundum	Proppant	1302-74-5	1.8	0.0
Ozone	Biocide	10028-15-6	1.3	0.0
2-Amino-2-methyl-1-propanol	Biocide	124-68-5	0.9	6.4
3,4,4-Trimethyloxazolidine	Biocide	75673-43-7	0.9	6.4

Table 2-1 continued

Component	Purpose	Chemical Abstract Service (CAS) Number	Overall % Wells Using	Marcellus Shale % Using
4,4-Dimethyloxazolidine	Biocide	51200-87-4	0.9	6.4
Dazomet	Biocide	533-74-2	0.9	0.0
Formaldehyde amine	Biocide	56652-26-7	0.8	5.5
Sodium polycarboxylate	Scale inhibitor	N/a	0.8	3.7
Ammonium bisulfite	Oxygen scavenger	10192-30-0	0.7	3.7
Chlorine dioxide	Biocide	10049-04-4	0.7	1.8

[1]Data from random sample of 762 documents downloaded from Fracfocus.org in February 2012 (approximately 10% of the total available at that time); overall sample includes 109 documents from wells in the Marcellus Shale region.

Table 2-2. Water used for drilling

Year	2010	2011	2012	2013
Pennsylvania				
No. wells drilled	1478	1822	1315	1167
Amount of water required (l)	28,082,000,000	34,618,000,000	24,985,000,000	22,173,000,000
Fresh water from surface sources (l)	19,938,220,000	24,578,780,000	17,739,350,000	15,742,830,000
West Virginia				
No. wells drilled	202	159	303	N/A
Amount of water required (l)	3,838,000,000	3,021,000,000	5,757,000,000	N/A
Fresh water from surface sources (l)	3,108,780,000	2,447,010,000	4,663,170,000	N/A
Ohio				
No. wells drilled	3	16	52	203
Amount of water required (l)	57,000,000	304,000,000	988,000,000	3,857,000,000
Fresh water from surface sources (l)	Not available	Not available	Not available	Not available

Chapter 3

GENERAL E3 ANALYSIS OF HYDRAULIC FRACTURING: ENERGY POTENTIAL

The United States produced 24.1 tcf of natural gas in 2012, of which 9.7 tcf (40%) was shale gas (USEIA 2014). The USEIA (2014) projects that the United States will produce 37.5 tcf annually by 2040, with 19.8 tcf (53%) from shale plays. Much of the increased production will come from the Marcellus and Utica Shale basins.

In 2012, the United States consumed 25.64 tcf of natural gas (USEIA 2014). Of that, electricity generation was the single biggest consumer, using 9.25 tcf or 35% of the total natural gas in the country. About 10 tcf d(39%) is used in various commercial and industrial applications, including natural gas vehicles. Residential consumption for heating, cooking fuel, and water heating used 4.2 tcf (16%). The natural gas industry itself used 8.2% of the natural gas consumed (2.1 tcf), between gas used in the drilling and field operations, pipeline compressor operations, and natural gas processing plants (USEIA 2014).

The USEIA (2014) predicts that annual consumption will increase to 31.6 tcf by 2040. The increase is predicted to be primarily a result of increased electricity production from natural gas to 11.2 tcf as coal-fired power plants are replaced with natural gas plants. Natural gas provided 23.8% of the 4.1 trillion kWh generated in the United States in 2010 and its share is projected to grow to 27% of the predicted 4.8 trillion kWh generated by 2040 (USEIA 2014).

The United States imported approximately 2.7 tcf of natural gas in 2014 (USEIA 2015*a*), of which 2.6 tcf were pipeline imports, primarily from Canada (99.94%) with a small amount (0.06%) from Mexico. The remainder of the imports was in the form of liquefied natural gas from overseas. Imports have declined in every year since 2007 (USEIA 2015*a*). The United States also exports natural gas at the same time it imports it. In 2014, the country exported 1.5 tcf, mostly in the form of pipeline natural gas (98.9%) (USEIA 2015*a*). Of the 1.4 tcf of pipeline gas exported, 0.77 tcf (52%) went to Canada and 0.71 tcf (48%) went to Mexico. The remainder of the natural gas exported was in the form of liquefied natural gas that was shipped to other countries. The United States is not expected to become a net exporter of natural gas by 2040 (USEIA 2014).

Estimates for the potential shale gas resources in the United States are highly variable, mainly due to the uncertainty in large, unproven reserves such as the Marcellus. The USEIA currently estimates that the proven and unproven technically recoverable resources (TRR) of shale gas are approximately 542 tcf (out of 2214 tcf for all natural gas sources) (USEIA 2012*e*). Of this, approximately 482 tcf are from unproven reserves. This estimate is much lower than the USEIA estimated in the 2011 Annual Energy Outlook (AEO) of 827 tcf in unproven reserves, mainly because of updates to the estimate for the Marcellus basin. In 2011, the USEIA estimated that the Marcellus contained 410 tcf TRR of shale gas, but lowered that estimated to 141 tcf for the 2012 AEO. Development in the Marcellus region in recent years has allowed for greater predictability of recoverable gas. The 2014 USEIA estimate of proved reserves was 64.9 tcf, an increase of 22.1 tcf over previous estimates (USEIA 2014*b*).

Given current annual natural gas consumption in the United States (24.37 tcf), the proven and unproven TRR of shale gas will last approximately 21 years and the Marcellus is predicted to produce enough to fuel less than 5.5 years of U. S. consumption.

Chapter 4

GENERAL E3 ANALYSIS OF HYDRAULIC FRACTURING: ECONOMICS

A number of factors drive the development of shale gas plays, including energy independence from other nations, potential reduction in greenhouse gas emissions, and economics. Natural gas is “big business” in the United States and its financial impact goes far beyond what consumers pay to heat their homes. From the moment a well location is identified, money is involved. Natural gas operators employ people to investigate potential wells and pay landowners to lease their property. Jobs are created (at least temporarily) to build an infrastructure of roads and pipelines and drill wells. Employees, in turn, spend money in the local community and support its economic infrastructure.

Along with the income that natural gas development brings, there are expenses to communities. Additional civil services may be required, including zoning officials, emergency responders, and road and bridge maintenance costs. There are also employment costs; the U. S. Energy Information Administration (2014*a*) estimates losses of jobs in other energy sectors as jobs in natural gas increase. There are also the less tangible costs to consider; such as losses of habitat or reduction in the quality of habitat for wildlife species. Changes in biodiversity can impact outdoor recreation and its economic effects on a region.

In this section, I attempt to quantify both the economic benefits and costs of hydraulic fracturing.

National pricing and pricing trends

The non-renewable energy sector comprises approximately 10% of the United States Gross Domestic Product (GDP), contributing approximately $1.4 trillion annually to the U. S. economy (United States Bureau Economic Analysis [USBEA] 2014, USEIA 2012). Natural gas alone contributes about 9% of that ($121 billion in 2012) (USEIA 2014).

Like most commodities, there are different listed prices at different points in the production cycle. For natural gas, spot prices (the current market prices) are usually determined by the price at the Henry Hub, a natural gas pipeline hub in Louisiana. Spot prices are generally much lower than consumer prices, which vary regionally and by sector. As of January 2015, the Henry Hub price was $2.99/MMBTU (one million British Thermal Units; equivalent to ~1000 ft^3), with a 12-month average price of $4.25/MMBTU (USEIA 2014). By comparison, the ten-year high Henry Hub price for natural gas was $13.422/MMBTU in October 2005 and the low was $1.95/MMBTU in April 2012.

The U. S. Energy Information Administration, in its 2014 Annual Energy Outlook, predicts that the consumption of natural gas in the United States will increase by about 0.8% per year between 2012 and 2040, primarily because of the increased use of natural gas for generating electricity, both through conversion of existing coal-fired electrical generation plants to natural gas and new natural gas-fired plants. The USEIA also predict that natural gas prices will remain below the 2005 peak price throughout this period, due to increased production of natural gas from shale formations (USEIA 2014). The Henry Hub price is projected to average $3.05/MMBTU in 2015 (USEIA 2015).

Income from natural gas

The primary economic benefit that the natural gas industry claims when bringing operations into a region, such as the Marcellus Shale, is the creation of jobs. The jobs affected by industry fall into 3 categories: direct, indirect, and induced (League of Women Voters 2009, Considine et. al. 2010). Direct jobs are those that fill the operator's immediate labor needs, such as road construction workers, drilling equipment operators, attorneys to handle the legal services required to obtain leases, and other direct needs. Indirect workers support the industry and include equipment and material suppliers. Induced jobs are those that are created when the income from the other categories is spent in the community in which it is earned, to purchase local goods and services. These include restaurant workers, local merchants, hotel operators, etc.

Within the Marcellus region, estimates on the number of jobs created by natural gas operations vary widely. Weinstein and Partridge (2011) estimate that direct, indirect, and induced impacts from the industry created about 20,000 new jobs in Pennsylvania from 2004 through 2010. Considine, et al. (2010) estimated that the industry created over 44,000 jobs in Pennsylvania in 2009 alone. IHS Global Insight, in an energy and economics analysis done for the Commonwealth of Pennsylvania in 2012, estimated that over 100,000 jobs were created by the natural gas industry in the Commonwealth in 2010. Not all of these sources indicated their estimation methodology, so it is difficult to determine the specific reasons for the differences. One reason may be that the loss of jobs in other industries (e.g. coal mining) that result from increased natural gas activity are included in some estimates, but may not be in others. Some include jobs that were created in the state, but filled by out-of-state workers. These increase revenue from induced impacts from those workers but do not increase local employment over the long term.

Other sources of revenue from natural gas operations in a region are from taxes and fees. In the Marcellus region, state and local governments receive increased taxes through income taxes on workers and corporations, royalty taxes on royalties paid to leaseholders, and severance or impact fees paid directly to governments by the operators. A severance tax is a tax imposed by a state on an operator who removes a natural resource from land within that state. Impact fees are fees paid to state or local governments to reimburse them for the impact an operation has on their jurisdiction. For example, it may be to compensate a county for damage to its roads or to compensate for increased costs of permit processing.

In the Marcellus region, Pennsylvania and New York are the only states without severance taxes on any natural resources, including natural gas. New York currently has no taxes or impact fees specific to natural gas production. Pennsylvania has only an impact fee. West Virginia imposes a 5% severance tax on the gross value of the natural gas produced. Ohio currently has a severance tax of approximately $0.025/mcf (thousand cubic foot) of natural gas produced, regardless of sales price, although the Ohio House of Representatives passed a bill in May 2014 to change the tax to 2.5% of the gross receipts. That bill stalled in the Ohio Senate and Governor John Kasich has proposed increasing the severance tax to 6.5% on natural gas from horizontal wells drilled in the Utica or Marcellus formations. His 2015-2016 budget for the state, proposed in February 2015, includes this increase in the severance tax and at this writing is being debated in the Ohio House of Representatives.

Pennsylvania's impact fee has been in effect since 2011 and through 2013 had collected $630 million in revenue. The annual amounts are based on the number of wells drilled and the price of natural gas. Most of the fee revenue (60%) stays at the county and municipal level, with the remainder going to various state agencies involved in drilling regulation and the Marcellus Legacy Fund, which is used for state environmental and infrastructure projects (NPR 2014). Given the change of administration in Pennsylvania in 2014, there is likely to be a change in the structure of taxation on natural gas production. Governor Tom Wolf recently proposed a 5% severance tax, along with a 4.7 cents/thousand cubic feet extraction tax, which are being debated in both the state House and Senate (Legere 2015).

Other tax revenues can increase with the influx of natural gas production in a region as well. Costanzo and Kelsey (2011) found that Pennsylvania counties with ≥150 wells reported an increase in state sales tax revenue of 11.36% from 2007 to 2010. They also found that personal income tax revenues increased more in counties that had more wells than in those with fewer wells or none at all (6.96% for counties with ≥10 wells vs 3.08% for counties with between 1 and 9 wells vs 0.89% for counties with no wells).

Costs of natural gas production

As with economic benefits, there are direct and indirect costs of natural gas production. Direct costs include all the costs incurred by the operators (e.g. leasing fees, drilling costs, operating costs, reclamation costs, etc) and those incurred by local governments such as officials to process permits. Indirect costs include increased long-term road maintenance costs required by heavy truck use, increased emergency services costs due to increased worker populations and higher risk occupations, and even potential decreases in property values. One survey in Washington County, PA showed that home sale prices decreased in correlation to the proximity of the home to a natural gas well, especially if the home's water supply came from a private well (Gopalakrishnan and Klaiber 2013).

The USEIA estimates that the operator's total average cost in 2009 was $31.38 (2015 equivalent = $37.90) for a barrel of oil equivalent (BOE) in natural gas (5618 ft^3) (USEIA 2014*a*). This average includes $18.65 (2015 equivalent = $22.50) to find and drill for the gas and $12.73 (2015 equivalent = $15.40) to operate the gas wells. In 2012, the total average cost was $33.48 (2015 equivalent = $36.10, US Bureau of Labor Statistics 2015). Given the USEIA's report of 1.9 trillion cubic feet (tcf) production in 2012, the total operators' cost for production and operation in that year was approximately $11.4 million (2015 equivalent = $13.3 million) in the Marcellus Shale region.

Even at the end of a well's production lifespan, there is a cost. Estimates of the cost to plug a well and reclaim the well pad range from $100,000–800,000, depending on the type of landscape to be restored (Hefley et al. 2011, Mitchell and Casman 2011). Agricultural landscapes are less expensive to restore than those that were once mature forest. Completely removing paved or gravel surfaces, regrading, adding topsoil, and planting appropriate native plants are more expensive than simply filling an impoundment pit and spreading non-native grass seed. Since most regulations do not specify exactly how the well pads are to be restored, operations may be inclined toward the cheaper alternatives, unless individual lease agreements stipulate otherwise.

Overall, natural gas operators in the Marcellus Shale region appear to be confident that horizontal drilling and hydraulic fracturing in the play will be profitable, as they continue to apply for permits in Pennsylvania, Ohio, and West Virginia, the 3 states that currently allow the technology (Figure 4-1). In Pennsylvania and Ohio, the rate at which permit applications have been submitted in the past 3 years has increased, while it has remained steady in West Virginia.

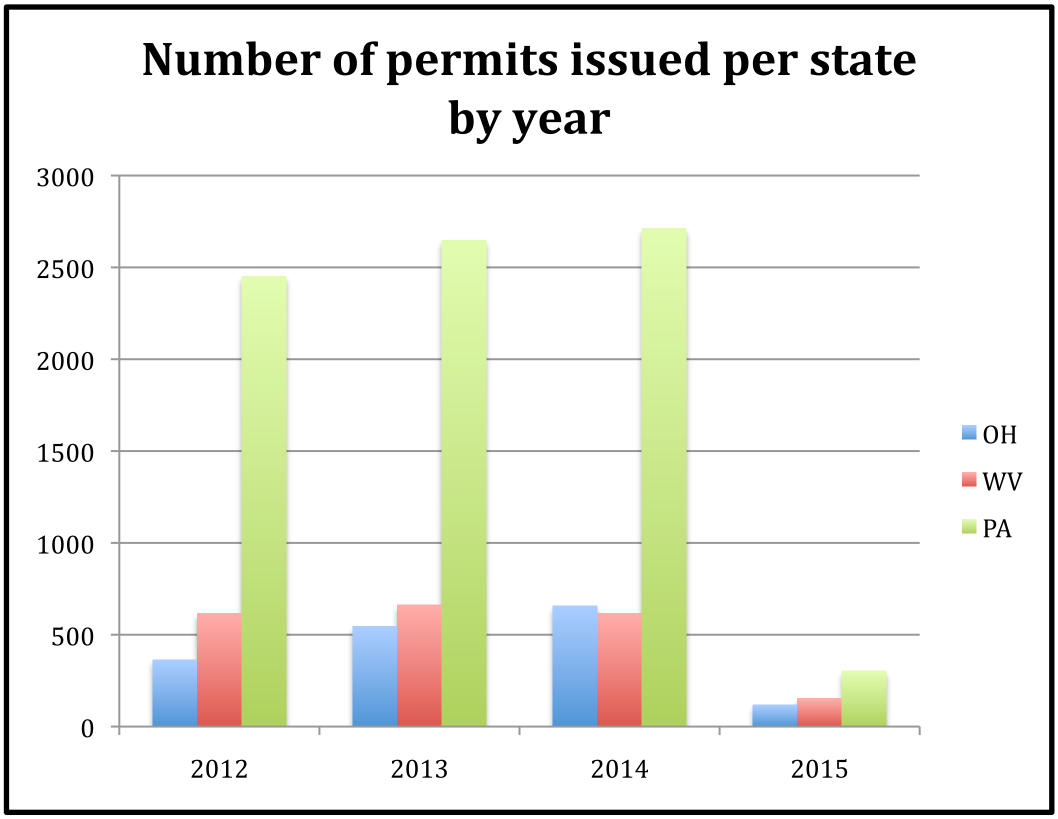
In addition to the easily quantifiable costs of natural gas development, there are less tangible costs as well. Changing the use of the land from either agricultural or forest incurs a loss of ecological services. Ecosystems, such as those in forests, provide services that can be valued. These ecosystem services are classified into 4 categories: provisioning services (timber, water, raw materials, etc), regulating services (erosion prevention, water quality control, carbon sequestration, etc), supporting services (biodiversity), and cultural services (aesthetic, recreational, etc) (Millenium Ecosystem Assessment 2005). De Groot et al. (2012) analyzed over 300 publications with global ecosystem service estimates and summarized them by the type of ecosystem (e.g. forest, wetland, etc.) in International$/ha[1]. The 2007 average estimate for temperate forest land was $3013/ha ± $5437, with a range of $278–16,406 and a median of $1,127 (2015 equivalent = $1,360). Given the amount of cleared land for a well pad (1–3.6 ha), the ecosystem service loss can be was quantified in 2007 at an average of $3,013–10,847 per well pad (2015 equivalent = $3,630–13,100).

Calculating the cost of loss of use of land that was previously agricultural varies from state to state. Pennsylvania and Ohio place specific values per acre of land of

[1] An International$ is a hypothetical monetary unit equivalent to the purchasing power of the US$ at the given point of time (de Groot et al. 2012). 1 International$=$1 USD

agricultural use for tax purposes, while West Virginia and New York do not (those states provide discounted tax rates for farm use). In Pennsylvania, agricultural use of land was valued at \$669–3,031/ha in 2012 (2015 equivalent = \$721–3,270), depending on the specific use of the land (PA Department of Agriculture 2012). In Ohio, cropland averaged \$1,778/ha (2015 equivalent = \$1,920, Ohio Department of Taxation 2012).

Figure 4-1. Number of natural gas permits issued per state by year



Note: 2015 numbers represent January through March only

Chapter 5

GENERAL E3 ANALYSIS OF HYDRAULIC FRACTURING: ENVIRONMENT

Most counties in the Marcellus Shale region are forested over more than 50% of the land area (Figure 5-1). The remainder is primarily agricultural, commercial and residential development, and some areas of wetland (USGS 2011). The Marcellus and Utica Shale region encompasses 5 physiographic areas, demarcated by distinct geology and topography: the Lower Great Lakes Plain, the Allegheny Plateau, the Ohio Hills, the Mid-Atlantic Ridge and Valley, and the Northern Cumberland Plateau (Figure 5-2, Partners in Flight 2012).

The Lower Great Lakes Plain area covers western New York State to the south of Lake Ontario and extends west to southern Ontario, Canada. The forests in this area are primarily oak-hickory, mixed hardwoods, and coniferous but approximately 74% of the area is used for agricultural purposes (Partners in Flight 2012).

The Allegheny Plateau is a mostly forested area stretching eastward from northeastern Ohio to the Catskill Mountains in New York, covering most of northern Pennsylvania. The forests in this area contain mostly oak (*Quercus* spp.) and hickory (*Carya* spp.) to the south, with beech (*Fagus* spp.) and maple (*Acer* spp.) to the north and some spruce- (*Picea* spp.) and fir- (*Abies* spp.) dominated patches in the eastern portion (Partners in Flight 2012).

To the southwest of the Allegheny Plateau is the Ohio Hills area, covering the remainder of eastern Ohio, western West Virginia, and southwestern Pennsylvania. More than half of this area is covered in oak-hickory forest (Partners in Flight 2012).

The Mid-Atlantic Ridge and Valley area covers eastern West Virginia and western Virginia. The forest ridges in this region are dominated by oak or oak-hickory mixes, with mixed hardwoods in the mountains (Partners in Flight 2012).

At the southwestern edge of the Marcellus/Utica region is the Northern Cumberland Plateau, covering eastern Kentucky and southwestern West Virginia. The forests in this area are predominantly oak and hickory (Partners in Flight 2012).

The Marcellus/Utica region provides habitat for hundreds of species of mammals, birds, fish, reptiles, amphibians, and mollusks. Table 5-1 lists the U.S. federal species of concern as well as the species of concern in New York, Pennsylvania, Ohio, and West Virginia. The primary effect of shale gas extraction on these species is most likely to be on their habitats. This section examines the potential impacts on terrestrial and aquatic habitats.

Habitat Considerations

Terrestrial Habitat Effects.– Construction of natural gas wells in forested areas requires complete clearing of the land for the wellpad, supporting infrastructure, pipelines, and roads needed to access the site. The well site is kept cleared during the production life of the well, but is generally replanted at the completion of operations at the site, depending on state requirements (USDOE 2009).

Effects to wildlife from the development of a natural gas facility are both direct and indirect. Clearing land and building the well pad, associated roads, and pipelines have the potential to indirectly affect wildlife by lowering the habitat quality and reducing habitat availability for resident and migratory species. Direct effects include displacement of residents, losses of individuals from vehicle collisions on new roads transecting previously intact habitat, and disruption of nests or dens.

Habitat Fragmentation and Edges.– Clearing of forested land causes habitat loss and fragmentation and an increase in habitat edges within the landscape, where one type of habitat abuts a different type (e.g., intact forest adjacent to a clearing). The introduction of edges in a habitat can change the variety and abundance of the species that use it, increasing those species that thrive in fields or early successional forest and decreasing those species that require deeply wooded habitat (Bátary and Báldi 2004). The degree and type of changes may also depend on the nature of the habitat that abuts the cleared area, with a greater increase of avian predator species in landscape edges in agricultural areas than in forested areas (Chalfoun et al. 2002). In sagebrush habitat, for example, Gilbert and Chalfoun (2011) found that increased density of wells was associated with a decreased population of sagebrush songbirds. Ingelfinger and Anderson (2004) reported a decrease in sagebrush songbird density of 64% along pipelines and a similar decrease of up to 60% along the dirt roads associated with natural gas extraction activities. Both research teams speculated that the lower densities of songbirds were a result of increased predator activity in the edge habitat.

Most published research on the effects of edge habitats on bird species shows that birds, especially passerines, are particularly affected by the introduction of fragmentation and edges into the landscape (Dijak and Thompson 2000, Chalfoun et al. 2002, Donovan and Flather 2002, Aquilani and Brewer 2004). While natural gas sites in grasslands are associated with an increase in non-native invasive plants, a reduction in native ground covers, and changes in soil properties (Nasen et al. 2011) which could reduce nesting attempts or success, typically concern is due to increased brood parasitism and nest predation (Aquilani and Brewer 2004, Bátary and Báldi 2004, Hoover et al. 2006). Brown-headed cowbirds (*Molothrus ater*), a common brood parasitic icterid, are found in much greater abundance in fragmented landscapes and along edges of forest fragments (Thompson et al. 2002, Aquilani and Brewer 2004, Hoover et al. 2006). Lloyd et al. (2005) found that brood parasitism of 17 different species of songbirds by brown-headed cowbirds increased with the proportion of developed land. Aquilani and Brewer (2004) found that in Northern Mississippi, wood thrush (*Hylocichla mustelina*) nest success was related to increased distance to the edge of a recently clearcut area in a wooded forest, which was also related to decreased cowbird abundance. Nest predation also increases at the edges of landscapes. Lloyd et al. (2005) found that, for ground-nesting birds, nest predation increased at forest edges in fragmented landscapes. Aquilani and Brewer (2004) found avian nest predators such as the blue jay (*Cyanocitta cristata*) and American crow (*Corvus brachyrhynchos*) were more abundant closer to edges of forested areas. Other corvids, such as ravens (*Corvus corax*) and magpies (*Pica spp*.), are also nest predators found in higher numbers in fragmented landscapes (Vander Haegen et al. 2002). Other predators are also found more frequently at landscape edges. Raccoons (*Procyon lotor*) are more abundant in edge habitats (Dijak and Thompson 2000). Black rat snakes (*Elaphe obsoleta*) predate avian nests and occupy edge habitat (Cox et al. 2012). Raptors have also been demonstrated to be nest predators at increased rates near the edges of forest patches (Cox et al. 2012). Rogers and Caro (1998) found that as mesopredators increased in an area, nest success of song sparrows (*Melospiza melodia*) decreased. While they studied nests in an agricultural landscape, it is not unreasonable to conclude that increases in predator populations in other types of habitat could also decrease nest success. With the cumulative effects of multiple predator types (bird, mammal, and reptile) and nest parasitism in an edge habitat, species that typically nest along the edges of landscapes could be at risk.

Bats are also affected by landscape fragmentation and edges; some species negatively and some positively (Morris et al. 2010). *Myotis* species of bats, such as the federally endangered Indiana bat (*Myotis sodalis*), the little brown bat (*Myotis lucifugus*), and the Northern long-eared bat (*Myotis septentrionalis*) prefer foraging in interior forest structures. Clearing of land reduces the amount of interior habitat available to these species, which in the Marcellus region also face threats from white-nose syndrome (WNS), a fungal infection known to have killed nearly 7 million individuals of seven different bat species, five of which are *Myotis* species, including two federally endangered species. The cumulative impact of WNS and habitat loss could be devastating to those species. For other bat species, such as the big brown bat (*Eptesicus fuscus*), the tricolored bat (*Perimyotis subflavus*), and the hoary bat (*Lasiurus cinereus*), edges provide additional area for foraging. These bats prefer foraging in open landscapes. Edges and the cleared areas between forest fragments provide more open areas for them to forage.

Roads.– In addition to creating edges in a landscape, roads also present other hazards to wildlife. For some small mammals and herpetofauna, roads can be a barrier to movement (Clark et al. 2001, Merriam et al. 1989, Marsh et al. 2005). Clark et al. (2001) and Merriam et al. (1989) both found that even narrow unpaved roads act as barriers to movement for small mammals, with fewer animals crossing roads than stay on the same side. Terrestrial salamanders, for example, are less likely to move across roads than they are to move within intact forest (Marsh et al. 2005). This has the potential to create isolated subpopulations. Traffic on roads associated with gas well sites is also a direct source of mortality through vehicle collisions, especially in breeding and wintering seasons (Forman and Alexander 1998). Some species of herps are also particularly susceptible to direct mortality from vehicles, due to their behavior. Slow-moving species may not be able to avoid being struck by vehicles and some species preferentially select road surfaces for thermoregulation or nesting (Fahrig and Rytwinski 2009).

Secondly, roads can become corridors, facilitating the immigration of invasive plant and animal species, which can cause loss of native habitat. As a result, native animals may avoid them. For example, Greater sage-grouse (*Centrocercus urophasianus*) avoid roads through its native sagebrush habitat, partly due to the presence of invasive cheatgrass (*Bromus tectorum*) along roads (Hess and Beck 2012).

Last, if traffic on a road is seasonal, the habitat along the side of the road can become an ecological trap. For example, Dietz et al. (2013) discovered that white-crowned sparrows (*Zonotrichia leucophrys*) did not avoid nesting along roads in a subalpine ecosystem in Colorado, USA when those roads were not heavily traveled in the early nesting season, but were more likely to desert their nests as traffic increased during the summer. They found that these birds preferred to place their nests in close proximity (within 10 m) to roads, but that nest success was inversely related to distance from the road.

Noise Disturbance.– In addition to landscape disturbances from construction and operation of the wells, natural gas production can cause noise disturbances. The compressor stations along gas pipelines typically produce between 75 and 90 dB(A) continuously and can reach 105 dB(A) (Bayne et al. 2008). Bayne et al. (2008) found that increased noise levels could be detected at distances of over 1 km into forested areas.

Birds are particularly susceptible to increased noise levels associated with natural gas pipelines, which have been shown to affect passerine density up to 700 m into the interior of the forest (Bayne et al. 2008). Bayne et al. (2008) believe that this chronic anthropogenic noise may disrupt territorial and/or mating calls by males. Wisner (2011) found that ambient noise can affect the frequency at which male Eastern bluebirds (*Sialia sialis*) sing. Males sing at significantly higher frequencies in disturbed areas with low frequency anthropogenic ambient noise. In Wisner's study, ambient noise levels in the disturbed areas averaged 42.7 dB(A), much lower than the noise levels produced by gas compressor stations. Presumably, higher ambient noise levels could cause even more change in bird song. Since birds learn song from adults of their species, there is the potential for young males in areas with noise disturbances to learn an altered song and if they move away from their natal territory, this could affect their ability to attract a mate.

Secondly, Bayne et al. (2008) believe that this chronic anthropogenic noise may also interfere with female responses to nestling vocalizations. Leonard and Horn (2008) found that nestling tree swallows (*Tachycineta bicolor*) modified their begging calls in the presence of high levels of ambient noise (65 dB[A]). The minimum frequency increased and the range of frequencies decreased, although nestling growth was not affected.

Cumulative effects.– Many factors occur together and can't necessarily be separated. Most of the published research on the specific effects of energy development on birds was conducted in the Western, North Central, and Midwestern United States, because oil and gas development has historically been more prevalent there than in the Marcellus region. As a result, much of the research focuses on habitats and species of birds not found in the Marcellus. For example, greater sage-grouse show declines in lek attendance, lower yearling and chick survival, decreased nesting rates, and increased distances of nests from leks in sites associated with gas development (Hess and Beck 2012). Lek attendance decreases with increasing well densities (Harju, et al. 2010). Over time, greater sage-grouse will abandon leks in areas of gas development and they will also avoid anthropogenic activity, such as that associated with roads. Walker et al. (2007) found that 38% of leks remained active within gas fields from 1997 to 2004–2005, compared to 84% of leks outside of gas fields. In Alberta, Canada, grouse avoided winter habitat within a 1.9 km radius of wells, prompting the authors to recommend a setback of 1900 m from any winter habitat (Carpenter et al. 2010).

Aquatic habitat effects.– The impact of withdrawal of water from surface water sources is highly dependent on the source itself. If the source is a small stream and the withdrawal is large, the impact is likely to be greater than a similar withdrawal from a large lake or river. In small streams, withdrawal of large amounts of water may concentrate the water downstream, potentially to the point where the water quality is low enough to adversely affect the aquatic ecosystem (Entrekin et al. 2011, Mitchell et al. 2013).

Low water levels in streams can increase the sediment, which can reduce populations and decrease general body condition and size of stream species such as brook trout (*Salvelinus fontinalis*), which is listed as a Threatened species in Ohio (Hakala and

Hartman, 2004). Low water levels also decrease dissolved oxygen (DO) levels, which negatively affects a variety of species. Many species of mussel are tolerant of low water levels, but elktoe (*Alasmidonta marginata*) and green floater (*Lasmigona subviridis)*, both of which are listed as Imperiled in West Virginia, are susceptible to the poor water conditions found in low water levels (DePhilip and Moberg 2010). Some species of aquatic salamander require flowing water all year and are susceptible to changes in water quality, including DO level and water temperature, which fluctuates more with low water levels. For example, the eastern hellbender (*Cryptobranchus alleganiensis*), which is Endangered in Ohio and Imperiled in West Virginia, requires cool water temperatures and is sensitive to changes in DO (DePhilip and Moberg 2010). Reptiles that winter at the bottom of streams and rivers often require high oxygen levels in the water to support their torpor. For example, wood turtles (*Glyptemys insculpta*), a species West Virginia lists as Vulnerable, requires high DO levels in order to survive overwintering in a streambed.

Water levels in streams, rivers, and lakes naturally fluctuate throughout the year. Additional withdrawal of water at times when surface water sources are already naturally low can negatively impact aquatic species, including some species of concern in the Marcellus region.

Waste Management Issues

Estimates of the volume of recovered flowback water from horizontal wells range from 10–70% of the fluid originally used to drill and fracture the well (URS Corporation 2009, USDOE 2009). Assuming an average of 19 mil L of fluid used in the process, drilling and fracturing a well can result in between 2-13 mil L of waste fluid to be managed.

The recovered flowback water is managed by a variety of methods including: 1) injection into underground wells drilled thousands of feet deep, 2) recycling for re-use in the pumping well, 3) treatment on-site or at either public or commercial water treatment plants, 4) evaporation ponds, or 5) spreading on the landscape or unpaved roads (USDOE 2009, Jackson et al. 2011). Prior to disposition, the fluid may be stored at the well pad in tanks or open impoundments and is subsequently transported for treatment via truck or pipeline.

Fracking waste fluid contains sand and the original chemicals added to aid in the fracking process. In addition, as the fluid permeates the shale, salts and other inorganic and organic constituents from the rock are dissolved in the fluid. As a result, the flowback can have high salinity, with total dissolved solids (TDS) of >200,000 ppm (USDOE 2009).

Injection of flowback water into private or commercial Class II disposal wells is the most common method of managing fracking waste (USDOE 2009). Using this method, waste fluid is injected deep underground, usually into limestone or sandstone formations (Figure 5-3). The wells into which the waste is injected must be protected by casings and cement linings (just as fracking wells must be) to protect underground water sources from contamination. In regions where there are few injection wells, the waste fluid is transported to other locations for injection. Pennsylvania, for example, had only 8 Class II underground injection wells in 2011, so most of the waste fluid to be injected had been transported to Ohio, the nearest state with injection wells (Phillips 2011).

Recycling of flowback water from fracking for use in future fracking operations is becoming more common, with at least one company in the Marcellus region recycling 100% of its fracturing fluid in 2010 (Soraghan 2013). In Pennsylvania, more than 70% of the wastewater is recycled, according to state DEP officials (Soraghan 2013). Depending on the content of the flowback water, it may need to be treated prior to reuse. For example, components with the potential to cause scaling in the well must be removed (e.g., calcium carbonate). Treatment technology is improving and operators expect to be able to reuse more of the flowback water in the future (USDOE 2009). Reuse may be more cost-effective for operators because it lowers the volume of freshwater required and reduces the amount of fluid that must be completely treated for release. Even if 100% of flowback water is recycled, however, drilling and fracturing a well would require a significant amount of freshwater, because only a portion of the flowback water is recovered.

In regions with lower precipitation, such as Texas, flowback water can be pumped from the well into onsite evaporation pits. The water is allowed to evaporate and the remaining concentrated contaminates are managed as solid waste. In the Marcellus region, evaporation ponds are not as effective, as the evaporation rate is lower than the precipitation rate (PA DEP 2001). If these pits are used for flowback water or for drilling mud, they can be hazardous to wildlife (United States Fish and Wildlife Service [USFWS] 2009). Birds mistake them for fresh water and other animals are attracted to insects that become trapped in the fluid. Some of the chemicals commonly used in hydraulic fracturing can be toxic and others, such as lauryl sulfate, are surfactants which can negatively affect the waterproofing of birds' feathers. Without proper waterproofing, birds cannot regulate their body temperature and can die from hypothermia (Friend and Franson 1999).

Some states allow flowback water to be applied to the surface of the landscape or spread on unpaved roads. In those cases, the fluid is either sprayed or pumped directly onto the surface and allowed to infiltrate the ground (Adams et al. 2011). Wildlife can come in contact with the fluid during the spraying or pumping process and after, as the fluid and the component chemicals are on the surface of the landscape. Over time, rain may wash the chemicals into local surface water sources (Adams et al. 2011).

Flowback water that is not injected, recycled, or applied to the surface is treated at public or commercial waste facilities and released into sewage systems or surface water sources (Wilson and VanBriesen 2012). Some of these waste treatment facilities are exempt from limits on the discharge of total dissolved solids and other components of hydraulic fracturing flowback waste fluid. For example, Pennsylvania has 8 treatment facilities that are exempt from discharge limits and that have treated flowback waste (Wilson and VanBriesen 2012). While the total volume of flowback waste has decreased from its peak in 2009, due primarily to the increase in recycling the fluid, waste discharged from exempt facilities into surface water sources does increase the concentrations of TDS and bromide (Hladik et al. 2014). Increased salinity in freshwater ecosystems can decrease biodiversity (Dalinsky et al. 2014). Given the high number of aquatic species of concern in the Marcellus Shale region as listed in Table 5-1, the impact of decreasing biodiversity in surface water sources could be correspondingly high.

Reclamation

Ideally, when operations are completed at a well site, the site would be restored to its original condition. However, since much of the land cleared (for well pads, supporting infrastructure of roads, and pipelines) was originally mature forest, the realistic goal of reclamation has been to make the land "acceptable for designated uses" (DOE 2009). Reclamation will generally include removing roads, regrading the land to prevent soil erosion, restoring topsoil, and revegetating the land. Reclamation can occur in stages, with removal of equipment and most of the well pad at the completion of drilling/fracturing and the rest (removal of access roads, plugging the well, etc) when the well's productive lifespan is complete (Mitchell and Casman 2011).

All the states in the region regulate that abandoned wells must be plugged and any pits on the site must be filled (more on regulations in the next section). The states generally do not regulate exactly how the sites are restored. For example, operators may or may not plant native species, depending on their specific permit requirements. They may not be required to remove concrete or gravel used at the well pad itself, which would directly impact the plant species that can re-grow on the site. Operators are not required to remove any invasive species that may have been established at the site during the drilling, fracturing, or production stages, which can also impede revegetation with native species.

There is also an increasing tendency of operators to drill multiple wells on a single well pad (Manda et al. 2014), with multiwell pads outnumbering single well pads in the Marcellus region since 2010. That will decrease the total amount of land disturbed overall, but will delay the reclamation effort at any given well pad, as wells will continue to be drilled over many years.

Figure 5-1 Proportion of forested land in the northeast and north central United States

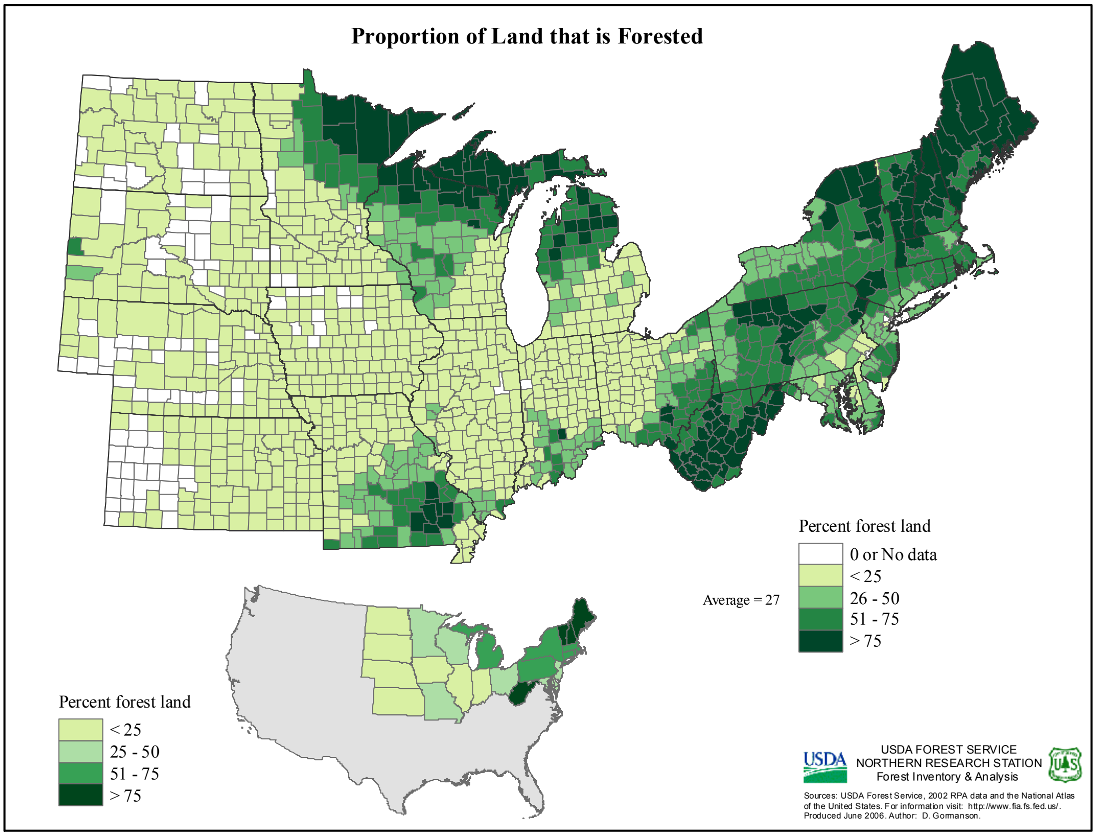
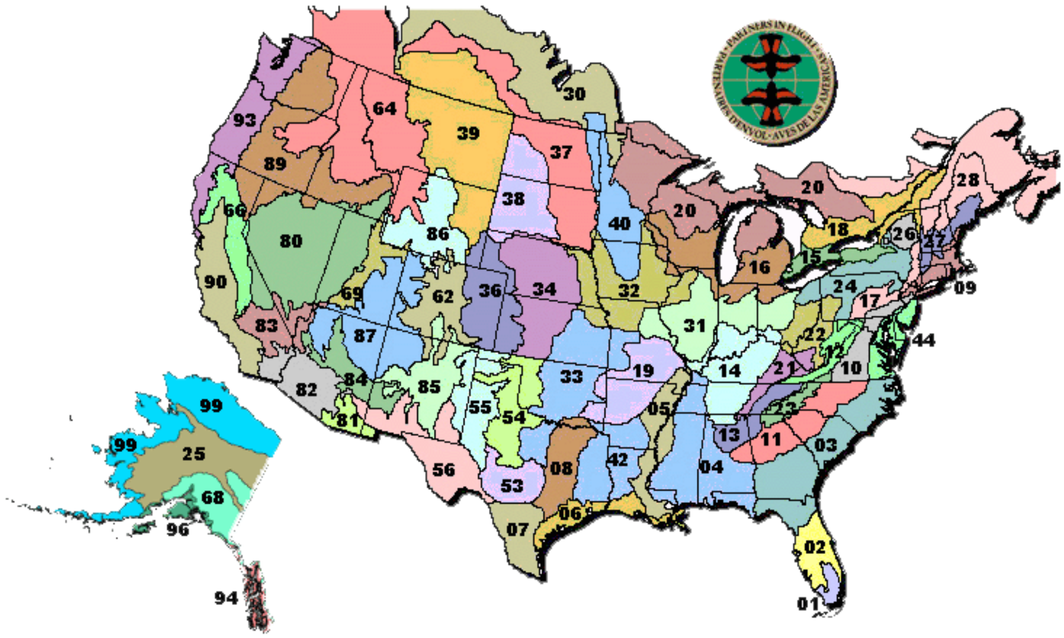
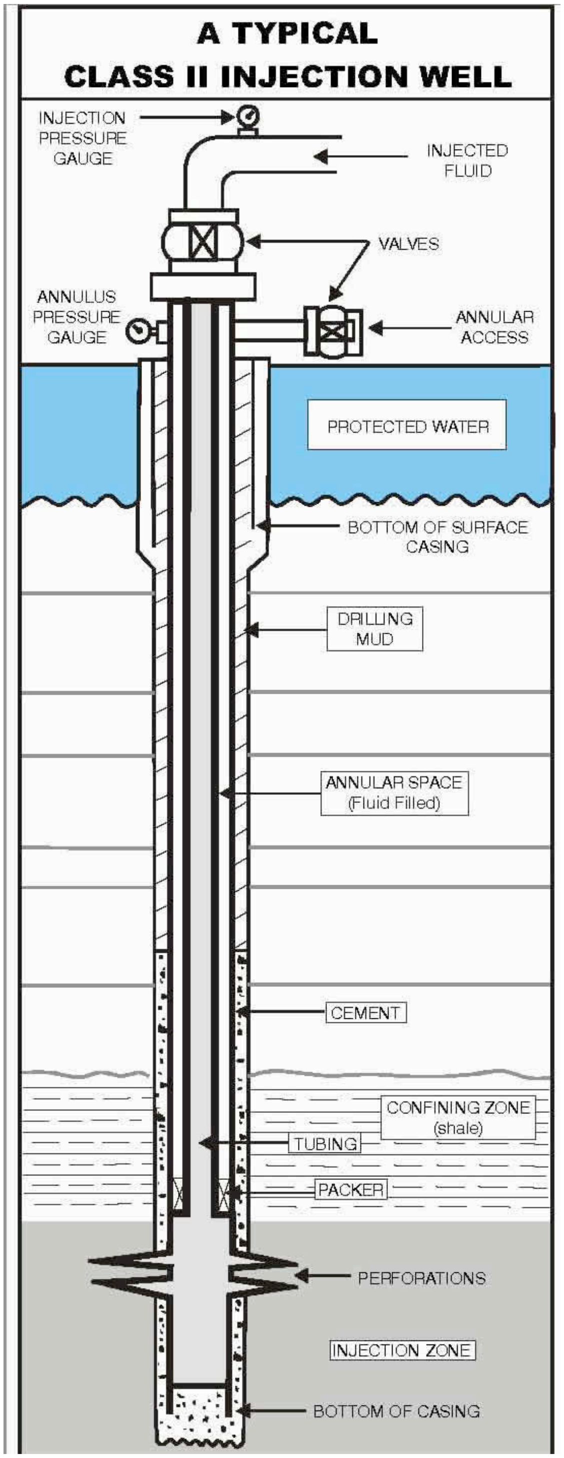


Figure 5-2 Physiographic regions of the United States and southern Canada



01 Subtropical Florida
02 Peninsular Florida
03 South Atlantic Coastal Plain
04 East Gulf Coastal Plain
05 Mississippi Alluvial Valley
06 Coastal Prairies
07 South Texas Brushlands
08 Oaks and Prairies
09 Southern New England
10 Mid Atlantic Piedmont
11 Southern Piedmont
12 Mid Atlantic Ridge and Valley
13 Southern Ridge and Valley
14 Interior Low Plateaus
15 Lower Great Lakes Plain
16 Upper Great Lakes Plain
17 Northern Ridge and Valley
18 St. Lawrence Plain
19 Ozark-Ouachita Plateau
20 Boreal Hardwood Transition
21 Northern Cumberland Plateau
22 Ohio Hills
23 Southern Blue Ridge
24 Allegheny Plateau
26 Adirondack Mountains
27 Northern New England
28 Spruce-Hardwood Forest
30 Aspen Parklands
31 Prairie Peninsula
32 Dissected Till Plains
33 Osage Plains
34 Central Mixed-grass Prairie
36 Central Shortgrass Prairie
37 Northern Mixed-grass Prairie
38 West River
39 Northern Shortgrass Prairie
40 Northern Tallgrass Prairie
42 West Gulf Coastal Plain
44 Mid Atlantic Coastal Plain
53 Edwards Plateau
54 Rolling Red Plains
55 Pecos and Staked Plains
56 Chihuahuan Desert
62 Southern Rocky Mountains
64 Central Rocky Mountains
66 Sierra Nevada
69 Utah Mountains
80 Basin and Range
81 Mexican Highlands
82 Sonoran Desert
83 Mojave Desert
84 Mogollon Rim
85 Mesa and Plains
86 Wyoming Basin
87 Colorado Plateau
89 Columbia Plateau
90 Central and Southern California Coast and Valleys
93 Southern Pacific Rainforests

Figure 5-3 Class II Underground injection well



Source: http://www.rrc.state.tx.us/about/faqs/images/injectionwelllg.jpg

Table 5-1. Endangered and Threatened Species in the Marcellus Shale Region[1]

Group	**Common Name**	Scientific Name	**State-Status**[2, 3]
Amphibian	Black mountain salamander	*Desmognathus welteri*	WV-S2
Amphibian	Black-bellied salamander	*Desmognathus quadramaculatus*	WV-S3
Amphibian	Blue-spotted salamander	*Ambystoma laterale*	OH-E
Amphibian	Cave salamander	*Eurycea lucifuga*	OH-E, WV-S3
Amphibian	Cheat mountain salamander	*Plethodon nettingi*	US-T, WV-S2
Amphibian	Cow knob salamander	*Plethodon punctatus*	WV-S2
Amphibian	Eastern cricket frog	*Acris crepitans crepitans*	WV-S2
Amphibian	Eastern hellbender	*Cryptobranchus alleganiensis*	US-E, OH-E, WV-S2
Amphibian	Eastern spadefoot	*Scaphiopus holbrookii*	OH-E, WV-S1
Amphibian	Green salamander	*Aneides aeneus*	OH-E, WV-S3
Amphibian	Jefferson salamander	*Ambystoma jeffersonianum*	WV-S2
Amphibian	Midland mud salamander	*Pseudotriton montanus diastictus*	OH-T, WV-S1
Amphibian	Northern cricket frog	*Acris crepitans*	NY-E
Amphibian	Northern leopard frog	*Rana pipiens*	WV-S1
Amphibian	Northern red salamander	*Pseudotriton ruber*	WV-S3
Amphibian	Smallmouth salamander	*Ambystoma texanum*	WV-S1
Amphibian	Tiger salamander	*Ambystoma tigrinum*	NY-E
Amphibian	Upland chorus frog	*Pseudacris feriarum*	WV-S3
Amphibian	West virginia spring salamander	*Gyrinophilus subterraneus*	WV-S1
Bird	American bittern	*Botaurus lentiginosus*	OH-E, PA-E, WV-S1B, WV-S1N
Bird	American black duck	*Anas rubripes*	WV-S2B, WV-S4N
Bird	American coot	*Fulica americana*	WV-S1B, WV-S3N
Bird	Appalachian bewick's wren	*Thryomanes bewickii altus*	WV-S1B, WV-S1N
Bird	Bald eagle	*Haliaeetus leucocephalus*	NY-T, PA-T, WV-S2B, WV-S3N
Bird	Bank swallow	*Riparia riparia*	WV-S2B
Bird	Barn owl	*Tyto alba*	OH-T, WV-S2B, WV-S2N
Bird	Bewick's wren	*Thryomanes bewickii*	OH-E
Bird	Black rail	*Laterallus jamaicensis*	NY-E
Bird	Black tern	*Nycticorax nycticorax*	NY-E, OH-E, PA-E
Bird	Black vulture	*Coragyps atratus*	WV-S3B, WV-S4N

Table 5-1 continued

Group	**Common Name**	Scientific Name	**State-Status**[2, 3]
Bird	Black-crowned night heron	*Nycticorax nycticorax*	OH-T, PA-E
Bird	Blackburnian warbler	*Dendroica fusca*	WV-S3B
Bird	Blackpoll warbler	*Setophaga striata*	PA-E
Bird	Bobolink	*Dolichonyx oryzivorus*	WV-S3B
Bird	Cattle egret	*Bubulcus ibis*	OH-E
Bird	Chuck-will's-widow	*Caprimulgus carolinensis*	WV-S1B
Bird	Clay-colored sparrow	*Spizella pallida*	WV-S1B
Bird	Cliff swallow	*Petrochelidon pyrrhonota*	WV-S3B
Bird	Common merganser	*Mergus merganser*	WV-S1B, WV-S3N
Bird	Common moorhen	*Gallinula chloropus*	WV-S1B
Bird	Common tern	*Sterna hirundo*	NY-T, OH-E, PA-E
Bird	Dickcissel	*Spiza americana*	PA-E, WV-S2B
Bird	Eskimo curlew	*Numenius borealis*	NY-E
Bird	Golden eagle	*Aquila chrysaetos*	NY-E
Bird	Golden-winged warbler	*Vermivora chrysoptera*	WV-S2B
Bird	Grasshopper sparrow	*Ammodramus savannarum*	WV-S3B
Bird	Great blue heron	*Ardea herodias*	WV-S3B, WV-S4N
Bird	Great egret	*Ardea alba*	PA-E
Bird	Henslow's sparrow	*Ammodramus henslowii*	NY-T, WV-S3B
Bird	Hooded merganser	*Lophodytes cucullatus*	WV-S1B, WV-S4N
Bird	Horned lark	*Eremophila alpestris*	US-T, WV-S2B, WV-S3N
Bird	King rail	*Rallus elegans*	NY-T, OH-E, PA-E, WV-S1B
Bird	Kirtland's warbler	*Dendroica kirtlandii*	US-E, OH-E
Bird	Lark sparrow	*Chondestes grammacus*	OH-E, WV-S1B
Bird	Least bittern	*Ixobrychus exilis*	NY-T, OH-T, PA-E
Bird	Least tern	*Sterna antillarum*	NY-T
Bird	Loggerhead shrike	*Lanius ludovicianus migrans*	NY-E, OH-E, PA-E, WV-S1B, WV-S2N
Bird	Long-eared owl	*Asio otus*	PA-T, WV-S1B, WV-S1N
Bird	Marsh wren	*Cistothorus palustris*	WV-S1B, WV-S2N
Bird	Nashville warbler	*Vermivora ruficapilla*	WV-S1B
Bird	Northern goshawk	*Accipiter gentilis*	WV-S1B, WV-S1N
Bird	Northern harrier	*Circus cyaneus*	NY-T, OH-E, PA-T, WV-S1B, WV-S3N

Table 5-1 continued

Group	Common Name	Scientific Name	State-Status[2, 3]
Bird	Northern saw-whet owl	*Aegolius acadicus*	WV-S2B, WV-S1N
Bird	Northern waterthrush	*Seiurus noveboracensis*	WV-S2B
Bird	Osprey	*Pandion haliaetus*	PA-T, WV-S2B
Bird	Peregrine falcon	*Falco peregrinus*	NY-E, OH-T, PA-E, WV-S1B, WV-S2N
Bird	Pied-billed grebe	*Podilymbus podiceps*	NY-T, WV-S2B, S4N
Bird	Pine siskin	*Carduelis pinus*	WV-S2B, WV-S4N
Bird	Piping plover	*Charadrius melodus*	US-T, NY-E, OH-E
Bird	Prothonotary warbler	*Protonotaria citrea*	WV-S2B
Bird	Red crossbill	*Loxia curvirostra*	WV-S2N
Bird	Red-headed woodpecker	*Melanerpes erythrocephalus*	WV-S2B, WV-S3N
Bird	Roseate tern	*Sterna dougallii*	US-E, NY-E
Bird	Sandhill crane	*Grus canadensis*	OH-E
Bird	Sedge wren	*Cistothorus platensis*	NY-T, PA-E, WV-S1B
Bird	Short-eared owl	*Asio flammeus*	NY-E, PA-E, WV-S1B, WV-S1N
Bird	Snowy egret	*Egretta thula*	OH-E
Bird	Sora	*Porzana carolina*	WV-S1B, WV-S1N
Bird	Spotted sandpiper	*Actitis macularius*	WV-S3B
Bird	Spruce grouse	*Falcipennis canadensis*	NY-E
Bird	Swainson's thrush	*Catharus ustulatus*	WV-S3B
Bird	Swainson's warbler	*Limnothlypis swainsonii*	WV-S3B
Bird	Upland sandpiper	*Bartramia longicauda*	NY-T, OH-E, PA-E
Bird	Trumpeter swan	*Cygnus buccinator*	OH-T
Bird	Vesper sparrow	*Pooecetes gramineus*	WV-S3B, WV-S2N
Bird	Virginia rail	*Rallus limicola*	WV-S1B, WV-S1N
Bird	White-throated sparrow	*Zonotrichia albicollis*	WV-S1B, WV-S4N
Bird	Wilson's snipe	*Gallinago delicata*	WV-S3B, WV-S3N
Bird	Yellow-bellied flycatcher	*Empidonax flaviventris*	PA-E
Bird	Yellow-bellied sapsucker	*Sphyrapicus varius*	WV-S1B, WV-S3N
Bird	Yellow-crowned night heron	*Nyctanassa violacea*	PA-E
Crustacean	A crayfish	*Cambarus longulus*	WV-S1
Crustacean	Big sandy crayfish	*Cambarus veteranus*	WV-S1
Crustacean	Digger crayfish	*Fallicambarus fodiens*	WV-S1
Crustacean	Cavespring crayfish	*Cambarus tenebrosus*	OH-T
Crustacean	Elk river crayfish	*Cambarus elkensis*	WV-S1

Table 5-1 continued

Group	**Common Name**	Scientific Name	**State-Status**[2, 3]
Crustacean	New river crayfish	*Cambarus chasmodactylus*	WV-S3
Crustacean	Sloan's crayfish	*Orconectes sloanii*	OH-T
Crustaceans	White river crayfish	*Procambarus acutus*	WV-S1
Fish	American brook lamprey	*Lampetra appendix*	WV-S2
Fish	American eel	*Anguilla rostrata*	OH-T, WV-S2
Fish	Appalachia darter	*Percina gymnocephala*	WV-S2
Fish	Banded killifish	*Fundulus diaphanus*	WV-S2
Fish	Banded sculpin	*Cottus carolinae*	WV-S2
Fish	Banded sunfish	*Enneacanthus obesus*	NY-T
Fish	Bigeye shiner	*Notropis boops*	OH-T, WV-S1
Fish	Bigmouth buffalo	*Ictiobus cyprinellus*	OH-T, WV-S1
Fish	Black buffalo	*Ictiobus niger*	WV-S2
Fish	Black bullhead	*Ameiurus melas*	WV-S1
Fish	Blue sucker	*Cycleptus elongatus*	OH-T, WV-S1
Fish	Bluebreast darter	*Etheostoma camurum*	NY-E
Fish	Bluestone sculpin	*Cottus sp. 1*	WV-S1
Fish	Brook trout	*Salvelinus fontinalis*	OH-T
Fish	Brown bullhead	*Ameiurus nebulosus*	WV-S2
Fish	Bullhead minnow	*Pimephales vigilax*	WV-S2
Fish	Candy darter	*Etheostoma osburni*	WV-S1
Fish	Central mudminnow	*Umbra limi*	WV-S1
Fish	Channel darter	*Percina copelandi*	OH-T, WV-S2, WV-S3
Fish	Cheat minnow	*Pararhinichthys bowersi*	WV-S1, WV-S2
Fish	Comely shiner	*Notropis amoenus*	WV-S3
Fish	Common shiner	*Luxilus cornutus*	WV-S1, WV-S2
Fish	Creek chubsucker	*Erimyzon oblongus*	WV-S3
Fish	Deepwater sculpin	*Myoxocephalus thompsoni*	NY-E
Fish	Diamond darter	*Crystallaria cincotta*	US-E, WV-S1
Fish	Dusky darter	*Percina sciera*	WV-S3
Fish	Eastern sand darter	*Ammocrypta pellucida*	NY-T, WV-S3
Fish	Eastern silvery minnow	*Hybognathus regius*	WV-S1
Fish	Ghost shiner	*Notropis buchanani*	WV-S3
Fish	Gilt darter	*Percina evides*	OH-E, WV-S2
Fish	Goldeye	*Hiodon alosoides*	OH-E, WV-S1

Table 5-1 continued

Group	Common Name	Scientific Name	State-Status[2, 3]
Fish	Grass pickerel	*Esox americanus vermiculatus*	WV-S1, WV-S2
Fish	Gravel chub	*Erimystax x-punctatus*	NY-T, WV-S1
Fish	Greater redhorse	*Moxostoma valenciennesi*	OH-T
Fish	Highfin carpsucker	*Carpiodes velifer*	WV-S1
Fish	Iowa darter	*Etheostoma exile*	OH-E
Fish	Kanawha minnow	*Phenacobius teretulus*	WV-S1
Fish	Lake chubsucker	*Erimyzon sucetta*	OH-T
Fish	Lake herring (cisco)	*Coregonus artedi*	OH-E
Fish	Lake sturgeon	*Acipenser fulvescens*	OH-E, NY-T
Fish	Longear sunfish	*Lepomis megalotis*	NY-T
Fish	Longfin darter	*Etheostoma longimanum*	WV-S1
Fish	Longhead darter	*Percina macrocephala*	NY-T, WV-S2
Fish	Longnose sucker	*Catostomus catostomus*	OH-E
Fish	Mooneye	*Hiodon tergisus*	NY-T
Fish	Mountain brook lamprey	*Ichthyomyzon greeleyi*	OH-E, WV-S1
Fish	Mountain madtom	*Noturus eleutherus*	OH-T, WV-S2
Fish	New river shiner	*Notropis scabriceps*	WV-S2
Fish	Northern brook lamprey	*Ichthyomyzon fossor*	OH-E, WV-S1
Fish	Northern madtom	*Noturus stigmosus*	OH-E, WV-S1
Fish	Ohio lamprey	*Ichthyomyzon bdellium*	OH-E, WV-S2, WV-S3
Fish	Orangespotted sunfish	*Lepomis humilis*	WV-S1
Fish	Paddlefish	*Polyodon spathula*	OH-T, WV-S1
Fish	Pearl dace	*Margariscus margarita*	WV-S2, WV-S3
Fish	Pirate perch	*Aphredoderus sayanus*	OH-E
Fish	Popeye shiner	*Notropis ariommus*	OH-E, WV-S2
Fish	Pugnose shiner	*Notropis anogenus*	NY-E
Fish	Pugnose minnow	*Opsopoeodus emiliae*	OH-E
Fish	Redfin shiner	*Lythrurus umbratilis*	WV-S3
Fish	Redside dace	*Clinostomus elongatus*	WV-S1, WV-S2
Fish	River carpsucker	*Carpiodes carpio*	WV-S3
Fish	River darter	*Percina shumardi*	OH-T, WV-S1
Fish	River redhorse	*Moxostoma carinatum*	WV-S3
Fish	River shiner	*Notropis blennius*	WV-S2
Fish	Rosefin shiner	*Lythrurus ardens*	WV-S1
Fish	Round whitefish	*Prosopium cylindraceum*	NY-E

Table 5-1 continued

Group	**Common Name**	Scientific Name	**State-Status[2, 3]**
Fish	Satinfin shiner	*Cyprinella analostana*	WV-S1
Fish	Scioto madtom	*Noturus trautmani*	US-E, OH-E
Fish	Shield darter	*Percina peltata*	WV-S1
Fish	Shoal chub	*Macrhybopsis hyostoma*	OH-E, WV-S2
Fish	Shorthead redhorse	*Moxostoma macrolepidotum*	WV-S1
Fish	Shortnose gar	*Lepisosteus platostomus*	OH-E
Fish	Shortnose sturgeon	*Acipenser brevirostrum*	US-E, NY-E
Fish	Shovelnose sturgeon	*Scaphirhynchus platorynchus*	OH-E, WV-S1
Fish	Silver chub	*Macrhybopsis storeriana*	WV-S3
Fish	Silver lamprey	*Ichthyomyzon unicuspis*	WV-S2, WV-S3
Fish	Slenderhead darter	*Percina phoxocephala*	WV-S1
Fish	Slimy sculpin	*Cottus cognatus*	WV-S1
Fish	Southern redbelly dace	*Phoxinus erythrogaster*	WV-S2, WV-S3
Fish	Spoonhead sculpin	*Cottus ricei*	NY-E
Fish	Spotted darter	*Etheostoma maculatum*	NY-T, OH-E, WV-S1
Fish	Spotted gar	*Lepisosteus oculatus*	OH-E
Fish	Streamside salamander	*Ambystoma barbouri*	WV-S1
Fish	Stripeback darter	*Percina notogramma*	WV-S1
Fish	Suckermouth minnow	*Phenacobius mirabilis*	WV-S3
Fish	Swallowtail shiner	*Notropis procne*	WV-S1
Fish	Swampdarter	*Etheostoma fusiforme*	NY-T
Fish	Tessellated darter	*Etheostoma olmstedi*	WV-S1, WV-S2
Fish	Tippecanoe darter	*Etheostoma tippecanoe*	OH-T, WV-S2
Fish	Tonguetied minnow	*Exoglossum laurae*	OH-T, WV-S2
Fish	Torrent sucker	*Thoburnia rhothoeca*	WV-S3
Fish	Warmouth	*Lepomis gulosus*	WV-S1
Fish	Western banded killifish	*Fundulus diaphanus menona*	OH-E
Mammal	Allegheny woodrat	*Neotoma magister*	OH-E, PA-T, WV-S3
Mammal	Appalachian cottontail	*Sylvilagus obscurus*	WV-S2
Mammal	Black bear	*Ursa americanus*	US-E, OH-E
Mammal	Bobcat	*Lynx rufus*	OH-T
Mammal	Eastern big-eared bat	*Corynorhinus rafinesquii*	WV-S1
Mammal	Eastern harvest mouse	*Reithrodontomys humulis*	OH-T
Mammal	Eastern spotted skunk	*Spilogale putorius*	WV-S1
Mammal	Evening bat	*Nycticeius humeralis*	WV-S1

Table 5-1 continued

Group	**Common Name**	Scientific Name	**State-Status**[2, 3]
Mammal	Golden mouse	*Ochrotomys nuttalli*	WV-S2
Mammal	Indiana bat	*Myotis sodalis*	US-E, NY-E, OH-E, PA-E, WV-S1
Mammal	Least shrew	*Cryptotis parva*	PA-E, WV-S2
Mammal	Long-tailed shrew	*Sorex dispar*	WV-S2, WV-S3
Mammal	Meadow jumping mouse	*Zapus hudsonius*	WV-S3
Mammal	Northern flying squirrel	*Glaucomys sabrinus*	PA-E
Mammal	Porcupine	*Erethizon dorsatum*	WV-S3
Mammal	Prairie vole	*Microtus ochrogaster*	WV-S3
Mammal	Silver-haired bat	*Lasionycteris noctivagans*	WV-S2
Mammal	Small-footed bat	*Myotis leibii*	PA-T, WV-S1
Mammal	Snowshoe hare	*Lepus americanus*	OH-E
Mammal	Southern bog lemming	*Synaptomys cooperi*	WV-S3
Mammal	Southern pygmy shrew	*Sorex hoyi winnemana*	WV-S2, WV-S3
Mammal	Southern rock vole	*Microtus chrotorrhinus carolinensis*	WV-S2
Mammal	Southern water shrew	*Sorex palustris punctulatus*	WV-S1
Mammal	Star-nosed mole	*Condylura cristata*	WV-S2
Mammal	Virginia big-eared bat	*Corynorhinus townsendii virginianus*	US-SAT, WV-S2
Mammal	West Virginia water shrew	*Sorex palustris punctulatus*	PA-T
Molluscs	Black sandshell	*Ligumia recta*	OH-T, WV-S2
Molluscs	Brook floater	*Alasmidonta varicosa*	NY-T, WV-S1
Molluscs	Butterfly	*Ellipsaria lineolata*	OH-E
Molluscs	Clubshell	*Pleurobema clava*	US-E, NY-E, OH-E, WV-S1
Molluscs	Creek heelsplitter	*Lasmigona compressa*	WV-S1
Molluscs	Cylindrical papershell	*Anodontoides ferussacianus*	WV-S2
Molluscs	Deertoe	*Truncilla truncata*	WV-S1
Molluscs	Dwarf wedge mussel	*Alasmidonta heterodon*	US-E, NY-E
Molluscs	Eastern elliptio	*Elliptio complanata*	WV-S2
Molluscs	Eastern pondmussel	*Ligumia nasuta*	OH-E
Molluscs	Ebonyshell	*Fusconaia ebena*	OH-E, WV-S1
Molluscs	Elephant-ear	*Elliptio crassidens*	OH-E, WV-S2
Molluscs	Elktoe	*Alasmidonta marginata*	WV-S2

Table 5-1 continued

Group	**Common Name**	Scientific Name	**State-Status**[2, 3]
Molluscs	Fanshell	*Cyprogenia stegaria*	US-E, OH-E, WV-S1
Molluscs	Fat pocketbook	*Potamilus capax*	US-E, NY-E
Molluscs	Fawnsfoot	*Truncilla donaciformis*	OH-T, WV-S1
Molluscs	Flat floater	*Anodonta suborbiculata*	WV-S1
Molluscs	Fragile papershell	*Leptodea fragilis*	WV-S2
Molluscs	Green floater	*Lasmigona subviridis*	NY-T, WV-S2
Molluscs	James spinymussel	*Pleurobema collina*	US-E, WV-S1
Molluscs	Lilliput	*Toxolasma parvus*	WV-S2
Molluscs	Little spectaclecase	*Villosa lienosa*	OH-E, WV-S1
Molluscs	Long-solid	*Fusconaia subrotunda*	OH-E, WV-S2
Molluscs	Mapleleaf	*Quadrula quadrula*	WV-S2
Molluscs	Midland smooth softshell	*Apalone mutica mutica*	WV-S1
Molluscs	Monkeyface	*Quadrula metanevra*	OH-E, WV-S1
Molluscs	Northern lance	*Elliptio fisheriana*	WV-S1
Molluscs	Northern riffleshell	*Epioblasma torulosa rangiana*	US-E, OH-E, WV-S1
Molluscs	Ohio pigtoe	*Pleurobema cordatum*	OH-E, WV-S2
Molluscs	Pink mucket	*Lampsilis abrupta*	US-E, NY-E, WV-S1
Molluscs	Pink papershell	*Potamilus ohiensis*	WV-S1
Molluscs	Pistolgrip	*Tritogonia verrucosa*	WV-S2
Molluscs	Plain pocketbook	*Lampsilis cardium*	WV-S2
Molluscs	Pocketbook	*Lampsilis ovata*	WV-S1
Molluscs	Pondhorn	*Uniomerus tetralasmus*	OH-T, WV-S1
Molluscs	Purple catspaw	*Epioblasma obliquata obliquata*	US-E, OH-E
Molluscs	Purple wartyback	*Cyclonaias tuberculata*	WV-S1
Molluscs	Pyramid pigtoe	*Pleurobema rubrum*	OH-E
Molluscs	Rabbitsfoot	*Quadrula cylindrica cylindrica*	US-T, OH-E
Molluscs	Rainbow	*Villosa iris*	WV-S2
Molluscs	Rayed bean	*Villosa fabalis*	US-E, NY-E, OH-E, WV-S1
Molluscs	Round pigtoe	*Pleurobema sintoxia*	WV-S2
Molluscs	Salamander mussel	*Simpsonaias ambigua*	WV-S1
Molluscs	Sharp-ridged pocketbook	*Lampsilis ovata*	OH-E
Molluscs	Sheepnose	*Plethobasus cyphyus*	US-E, OH-E, WV-S1
Molluscs	Snuffbox	*Epioblasma triquetra*	US-E, OH-E, WV-S2

Table 5-1 continued

Group	Common Name	Scientific Name	State-Status[2, 3]
Molluscs	Spectaclecase	*Cumberlandia monodonta*	US-E, WV-S1
Molluscs	Wavy-rayed lampmussel	*Lampsilis fasciola*	NY-T, WV-S2
Molluscs	White catspaw	*Epioblasma obliquata perobliqua*	US-E, OH-E
Molluscs	White heelsplitter	*Lasmigona complanata*	WV-S2
Molluscs	Yellow lampmussel	*Lampsilis cariosa*	WV-S1
Molluscs	Yellow sandshell	*Lampsilis teres*	OH-E, WV-S1
Reptile	Blanding's turtle	*Emydoidea blandingii*	NY-T, OH-T
Reptile	Bog turtle	*Clemmys muhlenbergii*	US-E, NY-E
Reptile	Broad-headed skink	*Eumeces laticeps*	WV-S2
Reptile	Copperbelly watersnake	*Nerodia erythrogaster neglecta*	US-T, OH-E
Reptile	Cornsnake	*Elaphe guttata*	WV-S1
Reptile	Eastern earthsnake	*Virginia valeriae valeriae*	WV-S2
Reptile	Eastern hog-nosed snake	*Heterodon platirhinos*	WV-S2
Reptile	Eastern kingsnake	*Lampropeltis getula getula*	WV-S2
Reptile	Eastern ribbonsnake	*Thamnophis sauritus*	WV-S2
Reptile	Eastern six-lined racerunner	*Aspidoscelis sexlineata*	WV-S1
Reptile	Fence lizard	*Sceloporus undulatus*	NY-T
Reptile	Kirtland's snake	*Clonophis kirtlandii*	OH-T
Reptile	Lake erie watersnake	*Nerodia sipedon insularum*	OH-T
Reptile	Little brown skink	*Scincella lateralis*	WV-S2
Reptile	Massasauga	*Sistrurus catenatus*	NY-E, OH-E
Reptile	Mountain earthsnake	*Virginia valeriae pulchra*	WV-S2
Reptile	Mud turtle	*Kinosternon subrubrum*	NY-E
Reptile	Northern coal skink	*Eumeces anthracinus anthracinus*	WV-S2
Reptile	Northern map turtle	*Graptemys geographica*	WV-S1
Reptile	Northern red-bellied cooter	*Pseudemys rubriventris*	WV-S2
Reptile	Plains gartersnake	*Thamnophis radix*	OH-E
Reptile	Ouachita map turtle	*Graptemys ouachitensis*	WV-S1
Reptile	Queen snake	*Regina septemvittata*	NY-E
Reptile	River cooter	*Pseudemys concinna*	WV-S2
Reptile	Rough greensnake	*Opheodrys aestivus*	WV-S2

Table 5-1 continued

Group	Common Name	Scientific Name	State-Status[2, 3]
Reptile	Spotted turtle	*Clemmys guttata*	OH-T, WV-S1
Reptile	Timber rattlesnake	*Crotalus horridus*	NY-T, OH-E, WV-S3
Reptile	Wood turtle	*Glyptemys insculpta*	WV-S3
Reptile	Wormsnake	*Carphophis amoenus*	WV-S3

[1]Does not include insects to due to inconsistency of reporting among states. Also does not include marine species (such as NY's Endangered Blue whale [*Balaenoptera musculus*]) or extirpated or extinct species.

[2]United States: E=Endangered, T=Threatened, SAT=Similarity of Appearance (Threatened); New York, Ohio, Pennsylvania: E = Endangered, T = Threatened. West Virginia: S1 = Critically Imperiled, S2 = Imperiled, S3 = Vulnerable, B = Breeding population, N = Non-breeding population.

[3]Sources: US – United States Fish and Wildlife Service 2014. NY – NY Department of Environmental Conservation 2013, OH – Ohio Department of Natural Resources 2012, PA – Pennsylvania Game Commission 2010, WV – West Virginia Department of Natural Resources 2012.

Chapter 6

REGULATION REVIEW

Legislation and regulation pertaining to hydraulic fracturing for natural gas development in the United States is a mix of federal, state, and local regulations. Additionally, in some parts of the country, regional bodies such as the Susquehanna River Basin Commission regulate specific aspects of fracking. Lower level regulations can be more restrictive than those at a higher level (i.e. state regulations can be more restrictive than federal), but cannot be less restrictive.

This section covers the federal legislation and regulations that apply to natural gas development in the United States. I will also discuss the applicable regional and state regulations in the Marcellus region including regulations set by the Susquehanna and Delaware River Basin Commissions and the states of Pennsylvania, Ohio, West Virginia, and New York.

Federal Regulation

A Foundation for Mining and Gas Exploration.– The United States government began regulating natural gas development on federal lands with the Mineral Leasing Act of 1920 (MLA; 30 U.S.C. § 181 et seq) and until the 1970s, focused on regulating leasing of federal land for gas development, natural gas pricing, or pipeline construction and operation. The MLA established limits on the size of plots used for exploration and for production purposes and restricted drilling to specified distances from plot boundaries. It required mineral rights owners to pay royalties to the federal government of up to 12.5% of the production value of the gas extracted. The Act does not directly address environmental concerns, but has provisions requiring permitees to "use all reasonable precautions to prevent waste of oil or gas developed in the land, or the entrance of water through wells drilled by [the permitee] to the oil sands of oil-bearing strata (Mineral Leasing Act)." While gas waste prevention could have the effect of preventing harm to the environment, the primary goal of the provision was to prevent damage to the gas deposit.

In 1938, the Natural Gas Act (15 U.S.C. 717 et *seq*.) was enacted to provide the first piece of federal legislation to specifically address natural gas issues, instead of including it in regulations of other natural resource extraction. The Natural Gas Act regulated pricing of gas by interstate pipeline companies, but did not address any environmental concerns. It granted authority to the Federal Power Commission (FPC) to set rates for the sale or transmission of natural gas across state lines. The FPC was also granted authority to regulate the construction, operation, and abandonment of interstate pipelines. The FPC was renamed the Federal Energy Regulatory Commission (FERC) in 1977 and, while FERC's authority to set prices was phased out during a deregulation movement beginning in the late 1970s, it still regulates construction, operation, and decommissioning of pipelines. The Natural Gas Policy Act of 1978 (15 U.S.C. § 3301 et seq) extended FERC's pipeline authority to *intra*state pipelines and well as interstate pipelines. When ruling on a permit, FERC is allowed to consider environmental concerns, particularly related to pipelines that cross bodies of water.

Adding Environmental Safeguards: National Environmental Protection Act.– By 1969, environmental safeguards to gas development activities were added through requirements of the National Environmental Protection Act (NEPA; 42 U.S.C. § 4321 et seq.). NEPA requires that all federal actions be evaluated for the potential environmental impact. If gas development occurs on federal land, the leasing of the site is considered a federal action and an evaluation of the environmental impact is required. The lead agency in the federal action is responsible for conducting this evaluation. If the initial evaluation indicates that there is no environmental impact, a Categorical Exclusion (CX) is issued. If the evaluation indicates that there will be an impact, the lead agency is required to perform an Environmental Assessment (EA). An EA can result in one of two outcomes: a Finding of No Significant Impact (FONSI) is issued or a ruling that a full Environmental Impact Statement (EIS) is required. The EIS is a detailed analysis of the impact of the proposed action, including alternatives considered. It must contain a description of the area affected and details of both the direct and indirect consequences to the environment of the action and all identified alternatives. For each adverse impact, the EIS must also include possible mitigation activities. The EIS must also include an assessment of the effects on the biotic ecosystem at the leased site and mitigation strategies for any adverse impacts. For example, if an endangered species exists in the area, the EIS must describe how that species' habitat will be preserved during development or restored following development. Environmental Assessments and Environmental Impact Statements are published for public comments once drafted, giving other governmental agencies (federal, state, or local), non-governmental organizations, and individual citizens the opportunity to challenge or support the conclusions.

Environmental Impact Statements prepared in support of a federal leasing agreement or permit are reviewed by the lead agency involved in the leasing or permitting process. That agency may choose to designate an alternate agency (such as the EPA or the United States Fish and Wildlife Service [USFWS]) to lead the assessment, but in any case, all EISs are reviewed by the EPA and published for public comment prior to finalization.

The Energy Policy Act of 2005 allows some federal actions related to oil and gas development to be automatically granted a Categorical Exclusion. To be eligible for a CX, the action must meet one of five criteria (EPAct 2005):

1. Individual surface disturbances of less than 5 acres; so long as the total surface disturbance on the lease is not greater than 150 acres and site-specific analysis in a document prepared pursuant to NEPA has been previously completed.
2. Drilling an oil or gas well at a location or well pad site at which drilling has occurred previously within 5 years prior to the date of spudding (i.e. start drilling) the well.
3. Drilling an oil or gas well within a developed field for which an approved land use plan or any environmental document prepared pursuant to NEPA analyzed such drilling as a reasonably foreseeable activity, so long as such plan or document was approved within 5 years prior to the date of spudding the well.
4. Placement of a pipeline in an approved right-of-way corridor, so long as the corridor was approved within 5 years prior to the date of placement of the pipeline.

5. Maintenance of a minor activity, other than any construction or major renovation or a building or facility.

Absent any of these criteria, the federal action is subject to NEPA and an Environmental Assessment must be completed.

Case Study: Environmental Impact Statement for Natural Gas Development: The Case of the West Tavaputs Plateau, Utah.– The West Tavaputs Plateau (WTP) in Duchesne, Carbon, and Uintah counties in Utah is mostly managed by the U. S. Bureau of Land Management, with 87% of the land under federal control. The remainder of the land rights are either privately controlled (5%) or managed by the state of Utah (8%). The region provides habitat for the federally Threatened Mexican spotted owl (*Strix occidentalis lucida*), federal candidate species Greater sage-grouse (*Centrocercus urophasianus*) and Yellow-billed cuckoo (*Coccyzus americanus*), as well as mule deer (*Odocoileus hemionus*) and elk (*Cervus Canadensis*). Federally Endangered Humpback chub (*Gila cypha*), Colorado pikeminnow (*Ptychocheilus lucius*), Bonytail chub (*Gila elegans*), and Razorback sucker (*Xyrauchen texanus*) can be found in the waters of the region.

In the early 2000s, the Bill Barrett Corporation (BBC) proposed extending development within a 55,818-hectare area of the WTP to extract natural gas. The proposed project area included portions of two Wilderness Study Areas (WSA): Desolation Canyon and Jack Canyon WSAs. BBC had previously been granted leases in the WTP, but had not applied for permits to drill. BBC projected that 250 million standard cubic feet of natural gas could be extracted daily from a proposed total of 807 gas wells on up to 538 well pads. BBC proposed active drilling to take place over 8 years, with a lifespan of 20 years for an individual well.

As required by NEPA, the Bureau of Land Management initiated an evaluation of the environmental impact of the proposed development. Environmental Assessments were completed in 2004, which evaluated the impact of seismic surveying and well development. In August 2005, the BLM published a Notice of Intent to initiate an Environmental Impact Study. The U. S. Fish and Wildlife Service, the Environmental Protection Agency, the State of Utah, and the 3 affected counties were all Cooperating Agencies, with BLM as the Lead Agency.

During the EIS process, the agencies considered 5 alternatives, including the original proposal from BBC and a “No Action” alternative as required by NEPA. They also considered a Transportation Impact Reduction Alternative, a Conservation Alternative, and a BLM-preferred Alternative. BLM considered the No Action Alternative to be the environmentally preferred alternative, but determined that it did not fulfill BLM’s land use policies. Each alternative was evaluated for the number of wells to be drilled, the number of well pads needed, the amount of concurrent drilling, the length of the drilling period, the drilling season, pipeline and pumping requirements, road requirements (for both construction of new roads and improvements to existing roads, short-term surface disturbance area, and long-term surface disturbance area. The Agency Preferred Alternative was very similar to the Proposed Action Alternative, but with fewer well pads, shorter drilling times, fewer concurrent drills, less road work, less new pipeline, and less surface disturbance.

The analysis of the five alternatives, including required mitigation for any adverse effects, was published in a Draft Environmental Impact Statement (DEIS) in February 2008. During the 90-day public comment period, the BLM received approximately 58,000 comments. These were reviewed and those that raised substantive issues and concerns were resolved in the Final Environmental Impact Statement, issued in July 2010.

The Record of Decision (ROD) was published concurrently and recommended a different alternative from those presented in the DEIS or FEIS. In the time between issuance of the DEIS and the FEIS, the originator of the initial request and proposal (BBC) submitted a modified request, which reduced the number of wells proposed to 626 on 120 well pads, of which only 63 would be newly created. The new proposal reduced the miles of new and improved roads required and included a proposal to bury 62% of the pipeline (contrasted with the original proposal, in which no pipeline was to be buried). It also substantially reduced both short-term and long-term surface disturbances. The original proposed action included 1460 hectares of short-term surface disturbance and 754 hectares of long-term surface disturbance. BBC's new proposal would cause only 649 hectares of short-term disturbance and 277 hectares of long-term disturbance, thereby reducing the impact of habitat loss and fragmentation.

NEPA allows the Lead Agency to select a different alternative than those included in the DEIS, if the different alternative falls within the range of the alternatives evaluated in the DEIS. BLM determined that BBC's new proposed action did fall within the range of the previously evaluated alternative and it was therefore named the Selected Alternative and approved in the ROD.

The ROD requires BBC and the appropriate federal agencies to take specific actions to protect wildlife when implementing the Selected Alternative. BBC must mitigate 4 acres of land for every acre disturbed long-term. To do this, they can improve undisturbed habitat by removing invasive plants, increasing sagebrush, or enhancing wet meadow or summer range habitats to benefit sage-grouse brooding success. BBC also must contribute toward the cost of triannual mule dear and elk population surveys conducted by BLM and other cooperating agencies. The BLM must provide an annual report on surface disturbance and on sage-grouse winter use of the project area. BLM must also review operator compliance on an annual basis.

The ROD also places restrictions on use of some of the project area. Sage grouse winter use areas are off-limits for surface disturbance unless the operator submits a specific permit request that indicates all the surface changes needed. Development is prohibited within two miles of known sage grouse leks between March 15 and July 15 and within half a mile on a known lek at any time. Travel is restricted during the dawn and dusk hours in the winter to minimize impacts on elk and deer. The ROD specifies that if more than 16" of snow is present, wildlife exit points must be plowed along roads at ¼ mile intervals.

Acts Focusing on Clean Air and Water.– In addition to the broad protections of NEPA, two other specific environmental quality acts address potential regulation of gas extraction. First, the Safe Drinking Water Act of 1974 (SDWA; 42 U.S.C. § 300F) regulates the quality of drinking water sources, including groundwater and surface water sources. It sets standards for the level of contaminants (both synthetic and natural) in the water. This includes limits on contaminants in fluids injected underground, although that regulation was not applied to fracturing fluids from gas (specifically, coalbed methane) development because the United States Environmental Protection Agency (EPA) considered fracturing to be a well stimulation technique rather than a storage technique and therefore not subject to the restrictions of the SDWA (EPA 2012a).

This continued until 1994, when the Legal Environmental Assistance Foundation (LEAF) filed a petition for the EPA to withdraw approval of Alabama's Underground Injection Control regulations. They alleged that Alabama's regulations did not meet the requirements of the SDWA because it did not include fluid injection to hydraulically fracture a well. The EPA declined the request and, in 1995, LEAF petitioned the 11th Circuit of the U. S. Court of Appeals. The Court ruled in 1997 that fracturing should be considered underground injection and therefore required regulation. EPA then conducted a study to determine the risk to drinking water sources from fracturing and concluded in 2004 that the "risk was small," except for the effects from diesel fuel. Therefore, the Energy Policy Act (EPAct) of 2005 (42 USC § 13201 et seq.) specifically exempted hydraulic fracturing from SDWA regulation, allowing the injection of fracturing fluids and agents, except for diesel fuel. However, the SDWA does allow for states to regulate this activity to protect local drinking water sources.

The Clean Water Act (CWA) of 1972 (33 U.S.C. §1251 et seq.; formally known as the Federal Water Pollution Control Act) provides for regulation of wastewater discharges into surface water. It established the National Pollutant Discharge Elimination System (NPDES) to control discharges into navigable waters. It set minimum limits on pollutants, but allowed the states to set further limits. CWA requires those who wish to discharge pollutants to obtain permits from either EPA or the state agency that regulates pollutant discharge. EPAct exempted hydraulic fracturing sediment runoff from federal regulation of wastewater discharge, but does not exempt the disposal of flowback fracturing fluid, which is still subject to NPDES permitting. In addition, EPAct does not preclude states from regulating sediment runoff, nor does it exempt any discharge (sediment or wastewater) from fracturing activities from state level regulation.

Clean Air Act (CAA) of 1970 (42 U.S.C. §7401 et seq.) regulates emissions from mobile and stationary sources. It authorized EPA to establish national air quality standards. CAA also authorizes EPA to establish New Source Performance Standards (NSPS) that apply to categories of industry. EPA delegates enforcement of the standards to the states and requires them to create State Implementation Plans that specify how the standards will be reached and enforced (EPA 2012*b*). The natural gas development NSPS was updated in April 2012 to include wells that are hydraulically fractured. The process of hydraulic fracturing, natural gas processing and transmission is susceptible to emission of methane and volatile organic compounds such as benzene, toluene, and xylene. The NSPS for gas development requires substantial reductions in the emission of these pollutants from new natural gas wells and processing, storage, and transmission facilities. The new rule requires industry to reduce emissions by 95% through either burning off the gases that escape from the well and processing/transmission equipment or by capturing that gas using a process called “green completion (EPA 2012c).” Green completions allow the operator to sell the captured gas. Effective 1 Jan 2015, all operators must capture the gas for use or sale, which EPA estimates will save the industry between $11 and $19 million (EPA 2012c).

Other federal laws affecting natural gas production.– The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, also known as Superfund) of 1980 (42 U.S.C. §9601 et seq.) requires responsible parties to cooperate in any cleanup required from a toxic release. While natural gas and the production wastes from gas development are exempted from Superfund regulations, the chemicals used in the fracking process are considered hazardous under CERCLA and are not exempted. Releases of toxic constituents in the fracking fluid must be handled in accordance with CERCLA.

The Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986 (42 U.S.C. §11001 et seq.) requires facilities that handle potentially dangerous chemicals to submit Material Safety Data Sheets (MSDS) to local authorities to allow them to prepare emergency plans for any possible chemical releases. MSDS are only required, however, when the facility stores at least 4,536 kg (10,000 lbs) of the chemical. Any amount under that threshold is not subject to EPCRA's reporting requirements.

Although it does not regulate natural gas activities directly, the Federal Land Policy and Management Act of 1976 authorized leasing or sale of federal subsurface mineral rights to private operators. It requires the U. S. Bureau of Land Management (BLM) to allow private leasing and maintain a multiple use standard for federal land. Environmental Assessments must be conducted for proposals to develop federal land for natural gas extraction and the FLPMA allows the BLM to include stipulations in the lease or sale agreement that would restrict activities that could have a negative environmental impact.

The Endangered Species Act of 1973 (ESA; 7 U.S.C. § 136, 16 U.S.C. § 1531 et seq.) can also affect shale gas development. Section 7 of the ESA requires all federal agencies to "insure that any action authorized, funded, or carried out by such agency is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species." Agencies must also consult with USFWS if the proposed action jeopardizes a candidate species or its habitat.

Those involved in activities not on federal land are prohibited from "taking" any endangered species without a federal permit. The ESA defines "take" as "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct." Taking also includes destruction or substantial modification of an endangered species' habitat. The USFWS may issue a take permit if they determine that the take is incidental to the action and if the applicant develops and implements a Habitat Conservation Plan (HCP). The HCP must describe the nature and impact of the taking, what alternative actions were considered, and how the applicant intends to minimize the risk of harm to the species or its habitat.

If the USFWS has determined that a species warrants protection under ESA but higher priorities preclude its actual listing, the species is considered a Candidate species. Candidate species may be protected by voluntary agreements between the property owner and the USFWS to conserve the habitat of the species. These Candidate Conservation Agreements (CCA) help to identify specific conservation activities (USFWS 2011). While voluntary, CCAs can be so successful that it is no longer necessary to list the species. CCAs are primarily developed between the USFWS and other federal or state agencies to conserve government-owned habitat. Candidate Conservation Agreements with Assurances (CCAAs) are similar to CCAs, but tend to be developed more frequently between the USFWS and private, non-governmental property owners (USFWS 2011). In addition to identifying habitat conservation efforts, CCAAs provide assurances to property owners that, if they implement the agreed upon conservation efforts and the Candidate species is listed as Endangered or Threatened in the future, no further conservation requirements need to be met. This eliminates uncertainty on the part of the property owner regarding future conservation efforts required for the habitat, which increases the willingness of property owners to engage in agreements.

Proposed/pending federal legislation.– As hydraulic fracturing came under public scrutiny in the late 2000s, the United States Congress came under more pressure to enact legislation regulating the natural gas industry. In 2009, Democratic senators in Pennsylvania (Robert Casey) and New York (Charles Schumer) and representatives from Colorado and New York simultaneously introduced bills in the U. S. Senate and House of Representatives. The Fracturing Responsibility and Awareness of Chemicals Act of 2011 (known as the FRAC Act) would have removed the natural gas industry's exemption from the Safe Drinking Water Act and would have required disclosure of all non-proprietary chemicals used in the hydraulic fracturing process. Both bills died in Committee, without coming to votes in the full Congress.

In March of 2011, the FRAC Act was re-introduced in both the House (H. R. 1084) and Senate (S. 587). In the House, it was referred to the House Committee on Energy and Commerce and was then referred to the Subcommittee on Environment and the Economy. H. R. 1084 died in committee. The Senate referred its version to the Senate Committee on Environment and Public Works, which referred it to the

Subcommittee on Water and Wildlife. It also died in Committee. Similar bills (H.R.1921 and S 1135) were re-introduced in the next Congress in 2013. No action has yet been taken on the House bill and the Senate bill has been referred to Committee, where it awaits further action. Given the current political climate in Congress it is unlikely that either bill will make it to a Committee vote, let alone a vote by the entire House or Senate.

Those in opposition to the FRAC Act introduced the Fracturing Regulations are Effective in State Hands (known as FRESH) bill in both the House and Senate (S.2248) in March 2012. The FRESH bill reaffirms the primacy of the states in regulating hydraulic fracturing. The House version (H.R.4322) was referred to the Committee on Natural Resources, the Committee on Agriculture, Transportation, and Infrastructure and to the Committee Energy and Commerce in April 2012. It died in Committee. The Senate version (S.2248) was referred to the Committee on Energy and Natural Resources and it, too, died in Committee.

In 2012, the Protecting States' Rights to Promote American Energy Security Act was introduced in the House (H. R. 2728), with bipartisan sponsorship. The Act would prohibit the federal government from enforcing federal regulation of hydraulic fracturing activities in states which already have regulations in place. The Act passed the House in November 2013, but died in the Senate. A similar bill (H. R. 1647) was introduced in March, 2015 and, as of this writing, was still in Committee.

The Bureau of Land Management published proposed rules for hydraulic fracturing on BLM-managed land, requiring disclosure of the chemical components of fracturing fluid. After multiple drafts and subsequent public comment periods, as of March 2015, the BLM has not yet issued the final rules.

Regional regulation review

Delaware River Basin Commission.– The Delaware River basin covers more than 3.5 million hectares in New York, Pennsylvania, New Jersey, and Delaware (Figure 6-1). It includes the 531 km Delaware River and its 216 tributaries, as well as the 202,537 hectares of the Delaware Bay (DRBC 2012*a*). It provides drinking water and water for agricultural and industrial uses for approximately 15 million people, including the residents of New York City.

The Commission was created in 1961 by a compact between New York State, Pennsylvania, New Jersey, Delaware, and the U. S. federal government, represented by the Army Corps of Engineers. The compact requires all projects with a potential to have a "substantial effect" on the waters of the Basin to be approved by the Commission. Delaware River Basin Water Code (18 CFR Part 410) regulates water quality and withdrawals as part of an overall water conservation plan for the Basin. It also sets standards for the designation of Special Protection Waters (SPW). SPW are those waters that the Commission has designated as having "exceptionally high scenic, recreational, ecological, and/or water supply values."

Regulations specific to the development of unconventional natural gas development started in 2008, when DRBC notified Stone Energy Corporation that it required DRBC approval for water withdrawals in the Delaware River Basin. DRBC determined that withdrawals for unconventional natural gas could have a substantial effect on the Basin and, as per the 1961 compact, plans must be submitted for DRBC review.

Also in 2008, DRBC notified all operators that all natural gas extraction from shale formations within the drainage area of Special Protection Waters (Figure 6-2) required commission approval, regardless of the amount of water withdrawn. However, DRBC determined that exploratory gas wells (i.e., wells drilled but not fractured) would be subject to state regulation only and not regulation by the DRBC.

In 2009 DRBC directed its staff to draft regulations specific to unconventional natural gas development. In 2010, the Commission voted to postpone unconventional natural gas project approvals until the regulations were final and decided to move forward with water withdrawal requests "in due course" (DRBC 2010). Later that year, DRBC modified its previous determination to include exploratory natural gas wells, which had previously been regulated only by the member states.

Draft regulations were published for comment in December 2010 and DRBC received approximately 69,000 comments including those from environmental and industry groups (DRBC 2012b). Environmental groups such as Delaware Riverkeeper Network, the Environmental Defense Fund, and the New York Riverkeeper and sportsmen's associations such as Trout Unlimited and the Delaware River Shad Fishermen's Association sent letters to DRBC urging further restrictions on wastewater management, fresh water supplies, and terrestrial and aquatic habitat degradation. Industry groups and energy companies commented that the proposed regulations placed greater restrictions than needed and they argued that the regulations would make natural gas development in the Delaware River Basin uneconomical and that water issues should be regulated by the states, not the DRBC.

DRBC scheduled a vote on the revised proposed regulations for November 21 2011. However, three days before the scheduled vote, the DRBC postponed the meeting to allow the commission members to further review the regulations. In May of the same year, New York State filed a federal lawsuit against DRBC to force DRBC to conduct an Environmental Assessment of hydraulic fracturing in the Delaware River Basin as per NEPA, since the Army Corps of Engineers is part of the Commission and NEPA requires an EA for any federal action (Bauers 2011). The EPA, USFWS, and National Park Service were also named in the suit as agencies that have conservation responsibilities for parts of the Basin. Consequently, in December 2011, the commissioners unanimously agreed to postpone review of all applications for water withdrawal within the State of New York until the state completes its own environmental review (DRBC 2011*a*). While a U.S. District Court dismissed the New York case by Sep 2012, because the regulations were still in the planning stage and any potential negative environmental impact is "speculative" (Smythe and Kary 2012), the DRBC had not yet rescheduled the vote (as of March 2015), leaving the regulations in draft and the moratorium on project approvals in place.

The revised 2011 proposed regulations call for:

1) A streamlined approval process (Approval by Delegated Authority, aka ADA) for most applications. Water sources that have previously been approved by DRBC can be used without further approval, if the usage is within the total allowable withdrawals. New sources must be approved by DRBC. Projects that use sources

other than fresh water (eg. recycled fracking fluid, mine drainage water) or water imported into the basin from outside sources are eligible for ADA decisions. However, projects proposed for National Park Service or other federal lands must be approved by docket.

2) All projects must include a Bulk Water Use and Management Approval (BWA) approved by DRBC, either by docket or ADA. The draft regulations also require testing of the surface water sources both prior to and following well pad construction. If a project application proposed bringing flowback or produced water into the basin from a source outside the basin, DRBC approval is required.
3) If Special Protection Waters or other high value water resources are to be used, DRBC requires a Natural Gas Development Plan (NGDP), which primarily relates to site planning. Any project that proposes more than 5 well pads or involves more than 1295 hectares also requires DRBC approval of an NGDP.
4) The regulations also specify how flowback and produced water must be handled. They require closed storage tanks and removal from the well pad location within 90 days. Open impoundments may only be used for storage of fresh water and may not contain any flowback or produced water. In addition, the regulations require DRBC approval for flowback or produced water to be discharged directly into groundwater or surface water or spread on roads or land surfaces.
5) DRBC will also require an Invasive Species Control Plan to be included in applications for projects that are proposed for locations where invasive species control is not already in place.

6) Water usage must be metered, as must recycled fluid usage. Project sponsors are required to file reports following hydraulic fracturing to include total water and recycled fluid usage as well as an accounting of all non-proprietary components of the fracturing fluid.

7) The draft regulations impose restrictions on the location of well pads. Well pads are not permitted in any floodway of the Basin, nor are they allowed in Upper Delaware Scenic and Recreational River areas without a variance from the Commission. DRBC has determined that "natural gas exploration and extraction activities are deemed incompatible land uses at locations in the UPDE Corridor (DRBC 2011*b*)." The draft regulations require minimum setbacks as follows:

   a) "Stream, water body or wetland – the greater of 300 ft. from the wellbore or 100 ft. from the nearest disturbance.

   b) Surface water supply intake – 1,000 ft. from nearest disturbance

   c) Water supply reservoir – 1,000 ft. from nearest disturbance

   d) Public water systems – 1,000 ft. from nearest disturbance

   e) Private water supply well – 500 ft. from nearest disturbance"

Susquehanna River Basin Commission.– The Susquehanna River basin covers over 7.1 million hectares in New York, Pennsylvania, and Maryland (Figure 6-3). It comprises over 78,800 km of waterways, from rivers to brooks and runs (SRBC 2006). The Chesapeake Bay gets approximately 50% of its fresh water from the Susquehanna River, making the health of the Susquehanna one of the biggest factors in the health of the Bay.

The Susquehanna River Basin Commission (SRBC) was formed as a result of the Susquehanna River Basin Compact in 1971. The Commission comprises representatives from the 3 states in the basin and the US Department of the Interior, with 3 out of 4 votes required to pass regulations. The SRBC regulates the use of water resources in the Susquehanna watershed, but takes only a coordinating role in water quality issues.

In 2008, SRBC published rules for the use of water by the energy industry, including specific language for natural gas development (18 CFR Parts 800-899). The regulations require approval by the SBRC for "any unconventional gas development project in the basin involving a withdrawal, diversion, or consumptive use [of water from the basin], regardless of quantity." Other categories of projects, such as other industry uses, agricultural uses, and public water supplies only require SRBC approval when consumptive use (i.e. use that does not allow for return of water to the basin) is projected to exceed an average of 20,000 gallons/day (75708 liters/day) over a 30-day period. SRBC considers all hydraulic fracturing water withdrawals to be consumptive, as most of the water used stays in the well.

For any gas development project to be approved, SRBC requires operators to provide details of the water source, amount of water to be withdrawn, proposed metering and monitoring of water use, mitigations in the event of low-flow conditions, and the anticipated impact of the project on surface water sources and threatened or endangered species and their habitats. In reviewing applications, SRBC considers those impacts, proposed mitigations, cumulative impact of the proposed project along with other projects, and the economic impact. If a project is approved, SRBC may also constrain the permit by limiting withdrawals during low-flow periods or requiring that the operator use alternative sources.

Unconventional natural gas operators are allowed to use tophole water (water brought to the surface during drilling), mining drainage water, rainwater collected on-site, recycled drilling or fracturing fluid and flowback, or water from an approved storage facility at another natural gas development site for drilling and fracturing wells, to conserve fresh water resources. Indeed, SRBC Resolution No. 2012-01 requires that operators seeking consumptive use permits must first consider using these lesser quality water sources before withdrawals from fresh water sources. Operators are required to report all water usage to the Commission at least quarterly and must also submit a complete post-fracture report of water usage during the drilling and fracturing processes for each well.

The regulations also allow SRBC to impose a moratorium or volume restrictions on water withdrawals during low-flow conditions, as it did in the summer of 2012 when it suspended withdrawals in the Basin. In December 2012, SRBC issued a new Low Flow Protection Policy for Water Withdrawals (SRBC Policy 2012-1). Separate regulations limiting the withdrawal of water from drainage areas less than or equal to 2590 hectares (headwater areas) were proposed in late December 2012 (SRBC 2012). As of January 2013, the regulations are still in draft and SRBC is collecting comments.

Great Lakes – St. Lawrence River Basin.– The Great Lakes Charter (1985) established a program of cooperative management of the water resources within the Great Lakes drainage area. It was signed by the governors of the 8 states that border the Great Lakes (Illinois, Indiana, Michigan, Minnesota, New York, Ohio, Pennsylvania, and

Wisconsin) and by the premiers of the provinces of Quebec and Ontario. The Charter authorized a committee of representatives from each member state or province to develop and implement a water management plan for the Basin as a "unified whole." The signatories to the Charter agreed to work together to protect the waters of the Basin, to consult with one another about water usage, and to collect and report data on water usage within their jurisdictions in the Basin.

The Great Lakes - St. Lawrence River Basin Sustainable Water Resources Agreement of 2005 formalized a water resources management agreement among the 8 states that border the Great Lakes and the provinces of Quebec and Ontario. In the United States, this was implemented via the Great Lakes - St. Lawrence River Basin Water Resources Compact of 2008. The Compact established the Great Lakes—St. Lawrence River Basin Water Resources Council (also known as the Council of Great Lakes Governors), made up of the governors of the 8 states that border the Great Lakes. The Compact prohibits "any new or increased diversion of any amount of water out of the Great Lakes Basin." It also specifies that water cannot be diverted from one lake's watershed to another. The Compact does provide for exceptions for water that will remain in the Basin, with allowances for consumptive use. Permits are required for new or increased withdrawals or consumptive use of water directly from the Lakes, unless the use averages < 100,000 gallons per day over a 90-day period. If the use will exceed an average of 5 million gallons per day, the project requires unanimous approval by the Great Lakes—St. Lawrence River Basin -Water Resources Council.

State regulation review

Pennsylvania.– In Pennsylvania, water usage is controlled by one of three regulatory bodies: the Delaware River Basin Commission (DRBC), the Susquehanna River Basin Commission (SRBC), and the Pennsylvania Department of Environmental Protection (PA DEP). The DRBC and SRBC are multi-state agencies and are discussed above.

The gas industry in Pennsylvania is regulated by the Oil and Gas Conservation Law of 1961 (58 P. S. § 405), the Coal and Gas Resource Coordination Act of 1984, the Oil and Gas Act of 1984, and Act 13 of 2012. It is also subject to state environmental laws, such as the Clean Streams Act of 1937 and the Water Resources Planning Act of 2002.

The Oil and Gas Conservation Law of 1961 required permits to drill gas wells, restricted non-vertical drilling, determined well spacing based primarily on boundaries of leased land, and required specific safety measures such as well casings to prevent waste spillage. It also governs the use of "forced pooling." Forced pooling refers to requiring landowners to allow gas extraction from a pool that lies under their property. The Oil and Gas Conservation Act stipulates that landowners must receive compensation in the form of royalty payments, but there is no formal lease between landowner and gas operator. This statute, as amended by the Coal and Gas Resource Coordination Act of 1984, does not currently apply to Marcellus Shale wells, as it only applies to wells which penetrate the Onondaga horizon or are 1158 m in depth, whichever is deeper. The Onondaga horizon lies beneath the Marcellus shale layer. Gas operations in Pennsylvania are subject to the common law doctrine of the "rule of capture," unless pooling is specifically regulated (Kramer and Anderson 2005). The "rule of capture" has been in effect since the 19th century and states that a mineral rights holder owns the rights to any gas produced from a well on his property, even if the gas has migrated from underneath a different property with a different mineral rights owner. While gas can be extracted from a neighboring property as a result of gas migration within the shale, the operator must have the agreement of the surface property owner to horizontally drill under their property.

The Oil and Gas Act of 1984 (25 Pa. Code § 78.1 – 78.906) set rules for permits for gas extraction, regulates waste pit design and use, set conditions under which gas operators are allowed to apply waste products to the land, sets requirements for site restoration, and requires gas operators to create plans for waste management and to replace water "affected by contamination or diminution" (25 Pa. Code § 78.51). The Oil and Gas Act stipulates that an operator is presumed to be responsible for contamination of any water supply within 6 months of drilling and within 304.8 m (1000 feet) of the well, unless the operator can prove that the contamination existed prior to drilling or did not occur within the 6-month period. The most effective way for operators to prove that their activities are not the cause of contamination of a well is to conduct a pre-drilling survey of the water sources within 304.8 m of the well. The law also requires that wells be set back 30.5 m (100 feet) from surface water sources and from wetlands that are >0.41 ha (1 acre) in area, although those setback requirements can be waived if the operator submits a plan to protect the areas from damage from a smaller setback.

Gas production in Pennsylvania is also subject to both federal and state environmental laws. Pennsylvania leaves the enforcement of the federal Clean Water Act to EPA, as the state has not exercised its right to primacy with respect to the CWA.

The Clean Streams Act of 1937 (as amended in 2006) prohibits discharge of industrial waste into any waters in Pennsylvania and requires operators to immediately notify the PA DEP in the event of a spill of hazardous waste. It requires erosion controls on disturbed land where the size of the disturbance is >2 ha (5 acres). However, shale gas well pads in Pennsylvania average just over 1.21 ha (3 acres) in size, and well pads of that size are exempt from the provisions of the Clean Streams Act (Johnson et al. 2010).

The Water Resources Planning Act of 2002 (25 Pa. Code § 110.1 – 110.604) requires operators who withdraw an average of 27,854 L/day (10,000 gallons/day) over a 30-day period within the same watershed to register their water use with PA DEP. Withdrawals are not restricted, but operators are required to report their water use to PA DEP annually.

Act 13 of 2012 (Impact Fee), made significant changes to unconventional gas operations in Pennsylvania. It allows counties and municipalities to impose an impact fee on unconventional gas wells. The amount of the fee is tied to natural gas market prices and ranges from $45,000 to $60,000 in the first year after a well is spud. Annual fees can extend for 15 years on a producing well, but the amount decreases over time. For example, in the second year of production, the fee ranges from $30,000 to $55,000, depending on natural gas prices. In the 15th year, the fee ranges from $5,000 to $10,000.

The Act establishes the Unconventional Gas Well Fund from which funds are directed to county conservation districts, counties, and municipalities for administration of ACT 13 and clean air and water laws, and to the PA Fish and Boat Commission for administrative costs of reviewing permit applications, PA Emergency Management Agency, the State Fire Commissioner, the PA Department of Transportation, the Housing

Affordability and Rehabilitation Enhancement Fund, and the Natural Gas Energy Development Program.

Act 13 prohibits municipalities from enacting local zoning ordinances to impose more restrictive conditions on unconventional gas operations than the state does. This section of the code is, as of January 2013, being contested in the Pennsylvania Supreme Court (Begos 2012, Levy 2012). Seven municipalities sued the state, alleging that this provision in the law overruled local rights to control property uses and therefore violated the state Constitution. A Commonwealth Court struck down the provision of Act in July 2012. Governor Tom Corbett's administration appealed the ruling to the state Supreme Court and arguments were heard in October 2012.

The Act also requires water management plans to be submitted to and reviewed by the PA DEP, in conjunction with the Susquehanna and Delaware River Basin and Great Lakes commissions. It established new setback requirements as follows:

> "No well site may be prepared or well drilled within 100 feet or, in the case of an unconventional well, 300 feet from the vertical well bore or 100 feet from the edge of the well site, whichever is greater, measured horizontally from any solid blue lined stream, spring or body of water … (2) The edge of the disturbed area associated with any unconventional well site must maintain a 100-foot setback from the edge of any solid blue lined stream [(i.e. a perennial stream)], spring or body of water … (3) No unconventional well may be drilled within 300 feet of any wetlands greater than one acre in size, and the edge of the disturbed area of any well site must maintain 100-foot setback from the

boundary of the wetlands."

The Act defines a wetland as an area "inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and which normally support, a prevalence of vegetation typically adapted for life in saturated soil conditions, including swamps, marshes, bogs, and similar areas."

Act 13 also increased the presumption of liability for pollution of a water supply. If an operator cannot prove, via a predrilling survey, that the contamination existed prior to drilling, it is presumed liable for pollution of a water supply within 762 m (2500 feet) of the well and within 12 months of drilling. Act 13 requires unconventional gas operators to publicly disclose the chemical components used in hydraulic fracturing. PA DEP has endorsed the use of FracFocus.org as the primary means of public disclosure (PA DEP 2012). The law does allow operators to keep confidential those components that they consider to be proprietary or trade secrets. However, in the event of exposure or a spill of fracturing components, operators are required to disclose even proprietary components to emergency management and medical personnel. The law does not require disclosure of naturally occurring chemicals in the shale that are returned with the fracturing flowback fluid, nor does it require disclosure of the components used in the drilling process.

Ohio.– Regulation of the oil and gas industry in Ohio started in 1883, when Ohio Law 80 was enacted to require casings in wells to protect aquifers from contamination. In 1965, Ohio Revised Code Chapter 1509 (Division of Oil and Gas Management – Oil and Gas) of Title XV (Conservation of Natural Resources) was put in place to regulate oil and gas production. Chapter 1509 established the Ohio Oil and Gas Commission, charged with reviewing project applications and hearing appeals. As amended by Senate Bill 501 in 1985 and Senate Bill 165 in 2010, the regulations specify minimum spacing requirements for wells based on the depth of the well. Wells drilled to a depth of 2000 – 4000 ft (610 – 1220 m) require 20 acres (8 hectares), while wells deeper than 4000 ft (1220 m) require 40 acres (16 hectares). Disturbed areas are required to be "compact and composed of contiguous land." During the lifespan of a well, natural gas that escapes from a well must be flared, not vented, if there is no economic market to sell the gas or means to capture it.

Chapter 1509 allows for temporary storage of brine in either pits or on-site tanks. Disposal of brine or other produced fluids is allowed via injection into Class II underground wells or by spreading it on land surfaces. Individuals are prohibited from spreading fluids in such quantities as to degrade the quality of surface water beyond the standards of the Safe Drinking Water Act or to cause damage or injury to the environment (although the law does not specify what constitutes damage or injury). Municipal and county governments may spread brine and other produced fluids on local roads, with restrictions regarding distance from surface water sources and vegetation.

Operators are also required to submit restoration plans for the land that is disturbed by the drilling process. Open pits must be filled within 2 months of the completion of drilling (14 days in urbanized locations). Parts of the disturbed area that are not required to be cleared for the production phase of the well must be regraded and planted within 6 months of drilling completion (3 months for urbanized areas). The entire disturbed area must be regraded and planted within 6 months of plugging the well (3 months for urbanized areas). Chapter 1509 does not specify what plantings are required and does not require native species; all that is required is there is enough plant material to prevent erosion and sedimentation.

Ohio Senate Bill 165 (2010) revised Chapter 1509 to allow taxes and fees to be collected from gas producers and landowners. A severance tax of $0.005 per 100 cubic feet of gas or $15.00 (whichever is greater) is payable quarterly. SB 165 also established an Injection Well Fee of up to $0.20 per barrel of fluid injected, payable annually by the owner of the injection well. All fees and taxes collected are credited to the Oil and Gas Well Fund, which pays for plugging of idle or orphaned wells, to correct potentially hazardous conditions that pose an "imminent health or safety risk," and for the administration of oil and gas regulations.

In June 2012, Ohio Senate Bill 315 was passed, revising existing gas laws. It requires operators to disclose all non-proprietary chemicals used in both the drilling and fracturing phases of well development. Disclosure to the public is made via FracFocus.org. Proprietary chemicals used in either phase must be disclosed to the Ohio Department of Natural Resources in the event of a spill. The law also requires disclosure of all chemicals (including proprietary) used in well development to physicians treating patients. Physicians are allowed to disclose proprietary chemical exposure to patients.

Senate Bill 315 also requires that operators test any drinking water wells within 457 m (1500 ft) of the well and include the results in the permit application. It also requires operators to identify the sources of water used in the drilling and fracturing of a well and project the rate at which water will be withdrawn from that source. The law specifically requires operators to identify if a water source is in the Ohio River watershed or the Lake Erie watershed.

Ohio Revised Code Chapter 1521 (Division of Soil and Water Conservation) of Title XV (Conservation of Natural Resources) regulates the consumptive use of water. It requires the chief of the Division of Soil and Water Resources to maintain an inventory of water usage in the state and authorizes the chief to create a water conservation plan to be used to assist regulators in determining the "reasonableness" of proposed water use.

Ohio Revised Code Chapter 1501 (Department of Natural Resources – General Provisions) of Title XV (Conservation of Natural Resources) requires operators to apply for a specific permit if the proposed water usage will divert > 100,000 gal (378,541 l) out of the Ohio River drainage basin. It also requires a permit for any operator proposing to increase water consumption by greater than an average of 2 million gal (7570824 l) per day over a 30-day period.

West Virginia.– In West Virginia, the Office of Oil and Gas (OOG) in the WV Department of Environmental Protection (WV DEP) regulates natural gas development. The OOG was established by WV Code, § 22-6 Office Of Oil And Gas; Oil And Gas Wells; Administration; Enforcement. In December 2011, natural gas development came under the regulations in WV Code, § 22-6A, the Horizontal Well Control Act (also known as the Horizontal Well Act).

The Horizontal Well Act applies to well sites that "disturb three acres or more of surface, excluding pipeline, gathering lines, and roads." Permit applications must include an erosion and sedimentation control plan. If the development of a natural gas well will require water withdrawals of > 210,000 gallons (794,936 l) during a 30-day period, the application must also include a water management plan. The water management plan must include details of water usage, including the type of the water source (e.g. surface water or groundwater), the projected volume of water to be withdrawn, the timing of withdrawals during the year, and a plan for the disposition of wastewater. The Act also requires operators to disclose the "anticipated additives" to WV DEP as part of the permit application. Following completion of the well, the actual additives used must be disclosed to WV DEP. The Act does not specify any exemptions for proprietary components.

Surface water withdrawals require additional information in the permit application, including the identification of water uses, the methods to be used to withdraw water, and appropriate evidence that the withdrawal will allow preservation of a "pass-by flow that is protective of the identified use of the stream" immediately downstream from the withdrawal. WV Code, § 22-13, the Natural Streams Preservation Act allows for some streams in the state to be designated by the legislature as "protected" with restrictions on their use. Streams with protected status cannot be "materially altered" unless the action is necessary to "prevent undue hardship." Neither "materially altered" nor "undue hardship" are defined in the code, which leaves interpretation up to the Director of WV DEP.

The Horizontal Well Act specifies proper placement of well sites with respect to surface water sources. No well pad is to be constructed nor well drilled within 100 ft (30.5 m) of any "perennial stream, natural or artificial lake, pond or reservoir, or a wetland" or within 300 ft (91 m) of a "naturally reproducing trout stream." If a well is drilled within 1500 ft (457 m) of a fresh water source and the operator has not performed predrilling tests of the water quality and flow, any contamination or diminution of the water supply is presumed to be caused by the drilling. This presumption is waived if the surface water owner refuses to allow predrilling testing or if more than 6 months have elapsed since the completion of the well.

The Horizontal Well Act requires all solid waste (drill cuttings and mud) to be sent to an approved waste facility, unless the surface owner consents to the waste being spread at the well site. Waste fluids may be temporarily stored onsite in open pits, but must be permanently disposed of and the pit filled in within six months of well completion. The Act does not specify appropriate methods of disposal of waste fluids, other than it must be done in accordance with other state or federal laws, rules, and regulations. West Virginia does allow the use of Class 2 Underground Injection Wells for the disposal of fluid produced by the fracturing process (W. Va. Code, § 22-6; Office Of Oil And Gas; Oil And Gas Wells; Administration; Enforcement).

The Act also requires reclamation of the well pad within six months of cessation of production activity, with allowances for partial reclamation in the case of multiple wells per pad. The objective of reclamation is to prevent erosion and sedimentation and the Act requires the operator to "grade or terrace and plant, seed or sod the area disturbed." It does not require native plantings or restoration to original grading or planting.

New York.– New York has a long history of conventional natural gas production. According to the Natural Gas Supply Association, an industry group, the first well in the United States was drilled in 1821, near Fredonia, New York (2011). In general, gas production is regulated under N.Y. Environmental Law § 23 Mineral Resources (AKA "Oil, Gas, and Solution Mining law"), enacted in 1963. As amended through the years since enactment, this law currently contains no rules or regulations specific to hydraulic fracturing.

The current Oil, Gas, and Mining Solutions law established spacing requirements for any wells drilled in the state, ranging from a minimum of 40 acres (16.3 hectares) per wellhead to 640 acres (259 hectares) for shale gas wells, depending on the depth of the well. The law also established a fee structure for operators of gas wells, with fees ranging from $190 for a well under 500 ft (152.4 m) deep to over $3800 for a well drilled to a depth of greater than 10,000 ft (3048 m).

The Oil, Gas, and Mining Solutions law also prohibits pollution of land, surface water, and/or groundwater. It does allow for temporary storage of produced water in onsite containers or open pits, but restricts such storage to a maximum of 45 days following the completion of drilling. The law contains no specific provisions to regulate reclamation of the land after completion of the well. Those activities are regulated under N.Y. Environmental Law § 23 Title 27 - Mineral Resources New York State Mined Land Reclamation Law, enacted in 1974. That law requires appropriate reclamation in order to "encourage productive use including but not restricted to the planting of forests, the planting of crops for harvest, the seeding of grass and legumes for grazing purposes, the protection and enhancement of wildlife and aquatic resources, the establishment of recreational, home, commercial, and industrial sites; to provide for the conservation, development, utilization, management and appropriate use of all the natural resources of such areas for compatible multiple purposes."

None of these regulations are specific to high volume hydraulic fracturing. When hydraulic fracturing was first proposed in New York State, the Department of Environmental Conservation (NY DEC) drafted a Supplemental Generic Environmental Impact Statement (SGEIS) specific to hydraulic fracturing. A Generic Environmental

Impact Statement in New York is similar to a Programmatic EIS at the US federal level in that it covers an entire type of activity and not just an individual instance of the activity. NY DEC published the first draft of the fracturing SGEIS for public comment in December 2009. In December 2010, then-Governor David Paterson issued an executive order prohibiting the issuance of permits for hydraulically fractured wells until the SGEIS and Department rules were finalized. NY DEC made changes to the SGEIS in response to comments and issued a preliminary revised SGEIS in July 2011 and the final revised draft SGEIS in September of that year. The NY DEC also promulgated rules for shale gas drilling and those rules were published for public comment in December 2012. The comment period ended in February 2013 and by state law, NY DEC had until the end of that month to finalize and publish rules or start the rulemaking process over, with new timelines (Hakim 2013). In early February 2013, Governor Andrew Cuomo decided to continue the ban on fracturing permits until the State Department of Health completed its study on the impacts to human health. The DOH reviewed the currently available information and assessed the risks to the environment and the residents of New York. In December 2014, the Commissioner of Health issued his report and found:

> "The current scientific information is insufficient. Furthermore, it is clear from the existing literature and experience that [hydraulic fracturing] activity has resulted in environmental impacts that are potentially adverse to public health. Until the science provides sufficient information to determine the level of risk to public health from [hydraulic fracturing] and whether the risks can be adequately managed, [hydraulic fracturing] should not proceed in New York State (Zucker 2014).

The rules proposed by NY DEC in December 2012 would revise Article 6 (Environmental Conservation) of the New York Codes, Rules, and Regulations. Specifically, the new rules modify Part 52 of NYCRR 6 (Use of State Lands Administered by the Division of Fish, Wildlife and Marine Resources) to prohibit natural gas drilling on any State land. Part 556 (Operating Practices) would require operators to prevent the escape of any gas into the air, effectively requiring flaring or recapture at the wellhead. Part 750 of 6 NYCRR would prohibit hydraulic fracturing that would "adversely affect a listed or proposed to be listed threatened or endangered species or its critical habitat."

The new rules add Part 560 (Operations Associated with High-Volume Hydraulic Fracturing) to 6 NYCRR. Part 560 defines high volume hydraulic fracturing as "the stimulation of a well using 300,000 gallons or more of water as the base fluid in the hydraulic fracturing fluid." Both fresh water and recycled flowback fluid are included in the total amount of water used in the fracturing process. Part 560 will also require permit applications to include the proposed volume of water to be used, as well as the proposed source(s) for the water. It will prohibit any part of the well pad from within 500 ft (152.4 m) of a "primary or principal aquifer boundary, perennial or intermittent stream, wetland, storm drain, lake, or pond" and within any 100-year floodplain. Operators will be required to provide NY DEC with a list of invasive species present at the well site and a plan for preventing the spread of invasives from the site. They will also be required to provide a plan to reclaim the land after well operations are complete, including best management practices for restoring native plants.

The new regulations would also require disclosure of the components of the fracturing fluid, including the proposed volume, weight, and concentration of each chemical component. Operators will also be required to document that the additives intended to be used "exhibit reduced aquatic toxicity and pose at least as low a potential risk to water resources and the environment as all known alternatives." Operators may request that components considered trade secret be exempt from public disclosure, although it will be required to include them in the application to NY DEC. Operators will be prohibited from storing flowback fluid in open pits or freshwater impoundments.

Part 560 will also require operators to build any needed roads "as far as practical from water resources" and to retain any stripped topsoil for use in reclamation. Fueling tanks will not be allowed within 500 ft (152.4 m) of streams, wetlands, lakes, or ponds. Operators will be required to reclaim the land within 45 days of well completion by seeding and mulching and to take action to prevent soil compaction.

Summary of state regulations.– The states in the Marcellus region have very different approaches to regulating hydraulic fracturing. New York is taking a cautious approach, while Pennsylvania is progressing more quickly. While most of the types of regulation are similar among the states (well spacing, setback distances from water sources, etc.), the details differ (Table 6-1). This may be a response to political pressure as much as it is to scientific understanding of the problems and the prevention thereof. Citizen activism and industry lobbying can sway lawmakers, and the resulting statutes can then affect rulemaking. For example, in New York State, groups of citizens opposed to hydraulic fracturing have formed in areas of the state in which hydraulic fracturing could occur if or when New York lifts its moratorium on permitting horizontally drilled wells (Chanatry 2013). These groups have had much influence on decisions on fracturing, particularly at the local level, where towns have attempted to use zoning laws to prohibit fracturing. They also actively participate in public comment periods for proposed regulations. On the other side of the issue, industry groups and citizen groups of landowners who are proponents of hydraulic fracturing can also influence decisions by lawmakers and regulators.

Even the most restrictive regulations will not prevent problems if they are not consistently enforced. Regulators also need sufficient resources to complete inspections and the standards of inspections should not vary among inspectors. While some states are increasing the number of state inspectors, the increase in drilling outpaces the increase in manpower (Lustgarten et al. 2013). Nationally, the number of wells drilled annually increased by 26% from 2003 – 2011, while enforcement staffing increased only 12% during that same time period (Lustgarten et al. 2013). The lack of enforcement staff makes it difficult for all wells to be inspected frequently. West Virginia, for example, had only 15 inspectors in 2012 to inspect > 55,000 wells (Malewitz 2012). In 2012 Ohio employed 30 inspectors, who inspected about half of the > 55,000 wells in that state. Quaranta et al., of West Virginia University, conducted a study of impoundment and pit safety for the West Virginia Office for Oil and Gas and found that the frequency of impoundment or pit inspections ranged widely (from 3 days to once every 2 months) and concluded that "infrequent inspections may allow problem areas to go unnoticed or delay corrective actions" (2012). They also found that inspectors used inconsistent standards in inspecting impoundments and pits and recommended to OOG that improvements in inspection methods were needed.

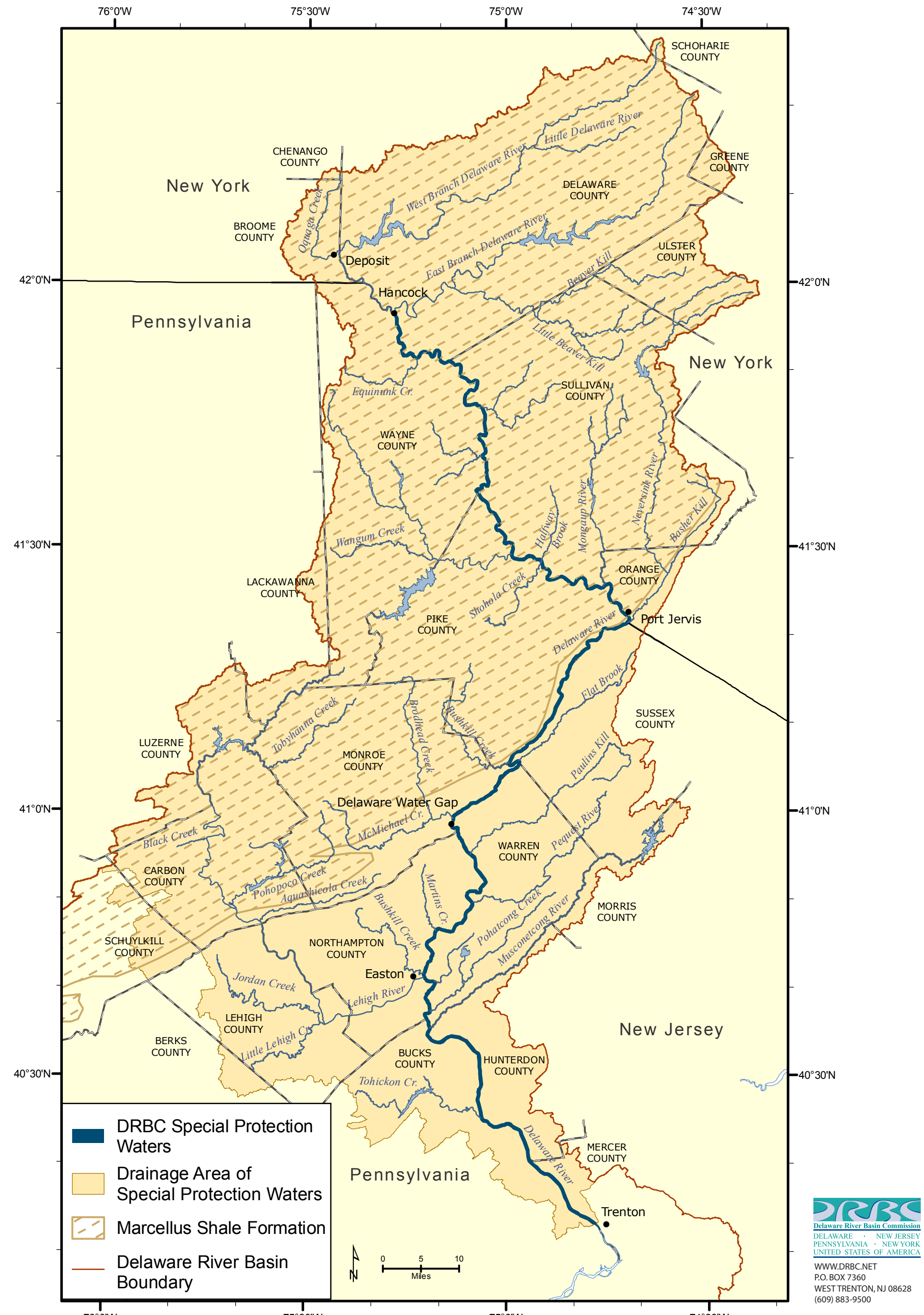
The differences in regulations and inspection standards among the states in the

Marcellus region could allow problems occurring in one state to affect another, particularly surface water problems. In regions such as the Ohio River watershed, there is no regional authority to oversee the use and quality of the water in the entire river basin. Wells adhering to the standards in one state may have a negative impact on other states, including states outside of the Marcellus region. For example, Ohio allows spreading of fracturing waste fluid on land and roads in certain circumstances. The runoff from that could potentially contaminate surface water sources in West Virginia, which does not allow waste fluid to be spread. It could also impact water sources in Kentucky, Tennessee, or Illinois, all states within the Ohio River Basin which have little or no Marcellus Shale Activity.

Figure 6-1 Delaware River Basin

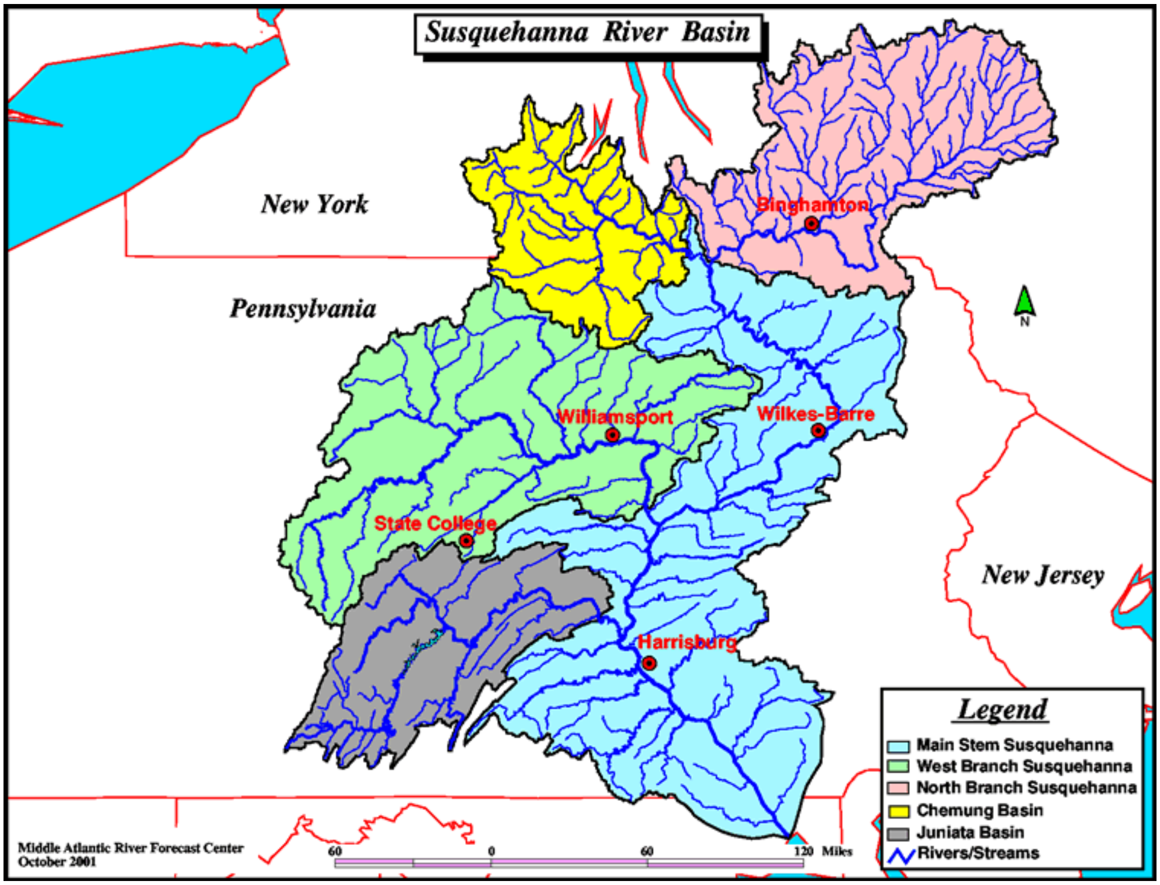
Source: Delaware River Basin Commission
(http://www.state.nj.us/drbc/library/documents/maps/relief1.pdf)

Figure 6-2. Map of Special Protection Waters in Delaware River Basin



Source: Delaware River Basin Commission
(http://www.state.nj.us/drbc/library/documents/maps/SPW-MarcellusShale.pdf)

Figure 6-3. Susquehanna River Basin Map



Source: National Oceanic and Atmospheric Administration, 2011
(http://www.erh.noaa.gov/marfc/Rivers/susquehanna.gif)

Table 6-1. Summary of state regulations

	Pennsylvania	**Ohio**	**West Virginia**	**New York (proposed regulations)**
Minimum well spacing	40 acres	20-40 acres, depending on depth	Not specified	40 - 640 acres, depending on depth
Setbacks	No well within 300 ft of surface water source; disturbed area must be at least 100 ft from surface water source	No well within 50 ft of surface water sources, unless authorized by Division of Oil and Gas Management	No well within 100 ft of surface water; 300 ft for trout streams	No well within 500 ft of surface water source or within a 100-year flood plain
Fracturing Fluid Component disclosure	Yes, by name and amount used; trade secrets exempt, except for emergency personnel	Yes, by name and amount used; trade secrets exempt, except for emergency and medical personnel	Yes, additives (but not amounts) must be listed; no trade secret exemption	Detailed disclosure required
Fracturing/flowback fluid storage	Temporary storage in open pits or storage tanks onsite allowed	Temporary storage in open pits or storage tanks onsite allowed	Temporary storage in open pits or storage tanks onsite allowed	Temporary storage in open pits prohibited
Restrictions on gas venting	None	Venting not allowed; must be captured or flared	None	Venting not allowed; must be captured or flared

Table 6-1 continued

	Pennsylvania	**Ohio**	**West Virginia**	**New York (proposed regulations)**
Fracturing fluid disposal	Injection well, commercial waste treatment	Injection well, spread on land/roads, commercial waste treatment	Injection well, but no other disposal methods specified	No injection wells
Water withdrawal	Consumptive water use plan required; reuse plan required	Consumptive water use plan required	Consumptive water use plan required	
Invasive species management	No specific requirements	No specific requirements	No specific requirements	Pre-drilling survey required; plan for prevention of spread
Reclamation/restoration requirements	Within 9 months of completion; no specific planting requirements	Pits filled within 2 months of completion; site replanted within 6 months of spudding; no specific planting requirements	Pits filled and site replanted within 6 months of completion	Pits filled within 45 days of completion; requires plan for restoration of native plants

Chapter 7

DISCUSSION AND RECOMMENDATIONS

The future of natural gas development is highly dependent on the price of natural gas. The profitability of hydraulic fracturing and horizontal drilling, which are costlier techniques than conventional drilling, decreases as the price of natural gas decreases. The price of natural gas decreases as increased production increases the supply. It's a difficult balance to predict. However, natural gas companies continue to apply for permits to drill at increasing (or at least consistent) levels in Pennsylvania, Ohio, and West Virginia, the 3 states where drilling is currently allowed (Figure 4-1). This shows they have confidence that the Marcellus Shale region is a profitable gas play and will be for the foreseeable future.

According to models developed by The Nature Conservancy (Johnson et al. 2010), in Pennsylvania alone, there could be as many as 60,000 new wells drilled by 2030. Depending on the number of wells drilled per well pad, this could mean as many as 15,000 well pads, along with associated roads and pipelines. At 8.8 acres per pad (3.1 acres for the well pad itself and 5.7 acres per pad for associated infrastructure), there is the potential for up to 132,000 acres of land to be cleared just in Pennsylvania. Many times that number of acres could be impacted by the creation of edge habitat.

Natural gas development technology has outpaced regulation. Original gas and oil drilling regulation was not intended to regulate horizontal wells, wells of a mile or more in length, or hydraulic fracturing technology. Legislators of the late 19th century or the early-mid 20th century did not anticipate the large volumes of water required, the large volumes of wastewater produced, or the chemicals used in the fracturing process. Early fracturing was performed under existing regulations, with regulators attempting to apply those original rules to the new process. Leaseholders weren't aware of the impacts fracturing could potentially have on their properties.

From a wildlife perspective, there was very little research available to demonstrate the effects that hydraulic fracturing could have on ecosystems. Indeed, even now there is need for additional research, especially on the aquatic habitat impacts of surface water removal, wellpad runoff, and wastewater disposal, but also on the effects of noise disturbance, seismic testing, and landscape disturbance.

Industry, scientists, non-governmental organizations (NGOs), and regulators need to develop a set of practices that represent the best knowledge available. These Best Management Practices (BMPs) will provide operators a clear set of guidelines in developing a well to minimize the negative impact on the local ecosystems. This work has been started by The Nature Conservancy (TNC), a non-profit organization whose mission is "to protect the lands and waters on which all life depends." (TNC 2015). TNC has compiled a database of >400 management practices from published best practices and scientific literature, developed a model to assess their effectiveness, and are currently compiling summaries of the most effective BMPs. The BMPs include recommendations for landscape-level planning, seasonal restrictions on activities, noise disturbances, and other gas development activities (Bearer et al. 2012).

In some practices, gas operators have made beneficial changes on their own. Flowback fluid is routinely re-used to fracture other wells or to refracture the original well. This reduces the volume of fresh water required in the fracturing process. It also reduces cost for the operator, both for fresh water withdrawal and for waste water disposal, so it benefits all concerned.

Operators frequently drill multiple horizontal wells on a single wellpad to save costs. This practice also minimizes landscape disturbance (including the creation of landscape edges) and is a beneficial side effect for the local flora and fauna.

Most changes, however, need to be enforced through legislation and regulation. For example, operators have objected to disclosing the chemical components in the fracturing fluid they use (Rizzuto 2014). They consider the information to be proprietary and have been reluctant to release it publicly. FracFocus.org was created as a compromise, to allow them to disclose the components of their fracturing fluids, but still designate some components as trade secrets. Even with that concession, not all operators have voluntarily included their information in the FracFocus database. As of this writing, not all jurisdictions require public disclosure. Enacting a federal regulation to require disclosure of all fracturing fluid components used within the United States will enable the public to understand exactly what is used.

Similarly, water use and waste disposal vary by region and by state. The Delaware River Basin Commission regulates both water withdrawal and water quality. The Susquehanna River Basin Commission regulates water withdrawal. In the Ohio River basin, there is no watershed-level regulatory body, so regulation is left to the individual states through which the river runs (Pennsylvania, Ohio, West Virginia, Kentucky, Indiana, and Illinois). There is no way to address watershed-level problems in that region. Decisions made by a state upstream could adversely affect a state downstream. The Ohio River provides habitat for many threatened and endangered species (Table 5-1) and it needs careful monitoring to protect those species. The affected states need to coordinate the use and quality of the Ohio River and all rivers in the region.

Water quality regulations also vary by state, since hydraulic fracturing is exempt from the federal Clean Water Act's sediment runoff regulations. Olmstead et al. (2013) found in a study they did in Pennsylvania that a higher number of wells upstream was associated with an increase in total suspended solids downstream. Pennsylvania does not require erosion control for disturbed land <5 acres and the average wellpad in that state is 3.1 acres. Erosion needs to be better controlled, especially given the number of additional wellpads anticipated in the coming years. If the states are unable to adequately protect surface water from runoff through their existing legislation, the natural gas exemption from the sediment runoff provisions of the federal Clean Water Act should be lifted.

Changes that may cost operators additional money are not likely to happen without regulatory pressure. For example, during reclamation, operators are required to replant the disturbed area to provide erosion control. However, most jurisdictions do not specify how the site is to be replanted, e.g. whether native or non-native plantings are to be used or whether the site is to be planted with grasses or mixed plantings of grasses, shrubs and trees. For an operator with cost as its driving force, spreading grass seed is the most economical choice and non-native grass seed is the cheapest choice. For example, Tall fescue (*Festuca arundinacea*) and Perennial ryegrass (*Lolium perenne*) are both commonly used non-native grasses for which seed can be purchased for <$2.00/lb (Ernst Seed 2015). Grass species native to the Marcellus region, such as Big Bluestem (*Andropogon gerardii*), Little Bluestem (*Schizachyrium scoparium*), and Indiangrass

(*Sorghastrum nutans*), for which seed costs $10-26/lb (Ernst Seed 2015). Other native species are even higher in price.

Clearly, native plantings provide the most effective means at restoring a natural ecosystem to the disturbed area. Without regulatory pressure, however, operators will have difficulty justifying the additional cost for reclamation activities, since both native and non-native plantings will fulfill the goal of erosion control. Regulators need to consider the goal of reclamation to be habitat restoration, not just the prevention of further damage by preventing further erosion.

As natural gas consumption increases, production will increase. All the stakeholders in the region need to be prepared for the additional development to come. Given that reality, scientists, industry, and regulators need to work together to manage the activity in the least harmful way possible.

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