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The Economic Impact of the Value Chain of a Marcellus Shale Well

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Pitt Business Working Papers - 2011

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Abstract:

The Economic Impact of the Value Chain of a Marcellus Shale Well Site examines the direct economic impact of a Marcellus Shale well located in Southwestern Pennsylvania. This study seeks to fill a critical information gap on the impact of gas drilling and extraction from Marcellus Shale deposits deep underground: an assessment of the economic impacts – emphasizing the direct economic impact, rather than just focusing on the perceived benefits and impacts affecting the region. Our analysis is based on extensive field research, including a site visit and interviews with industry participants. It is further cross-validated by examining similar costs for development of Marcellus Wells by a vertically-integrated exploration and production firm.

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1 Executive Summary

This project seeks to fill a critical information gap on the impact of gas drilling and extraction from Marcellus Shale deposits deep underground: an assessment of the economic impacts – emphasizing the direct economic impact, rather than just focusing on the perceived benefits and impacts affecting the region. Shaun Seydor, Director of PantherlabWorks, and Pitt Business Professor Bill Hefley, PhD, led a Pitt student delegation tour of a Marcellus Shale well site in Washington County. Partnering with EQT to explore the supply chain of a single Marcellus Shale well, both an undergraduate Business class and a Katz MBA class had an all-access tour of an operating Marcellus Shale drilling site in Washington, County, PA, on Friday March 25th, 2011. The courses and subsequent research seek to quantify aspects of the value chain for the life-cycle of a single Marcellus Shale well drilling operation. By using a single well as a standard unit of measure, the study gains breadth in its application. This project sought to quantify the “business” factors of a single Marcellus Shale well value chain, in order to then characterize the supply chain complexities and inform the identification of regional entrepreneurship opportunities.

Our goal with this study is to provide a realistic picture of the direct costs of natural gas drilling. Section 2 provides a brief introduction to the Marcellus Shale industry. Section 3 looks at the concept of economic impacts, and then at each of the three types of impact – the direct effect, the indirect effect, and the induced effect. Section 3 concludes with an examination of the limitations of this study. Section 4 addresses each phase in the process of creating a Marcellus Shale well, while Section 5 walks through the direct expenditures for each phase of a typical Marcellus Shale well site. This section follows the process, examining each step for the direct costs involved. Section 6 examines issues and opportunities not addressed by this report. Some of these may have the potential to change the economic impacts of Marcellus plays. Section 7 wraps up by summarizing the direct impact of a Marcellus Shale well. An appendix provides a validation of our direct impact estimates by examining the estimated costs of a vertically integrated natural gas producer.

2 Industry Overview

Shale gas development in recent years has changed the energy discussion in the US, as existing reserves of natural gas coupled with horizontal drilling and hydraulic fracturing make exploitation of these reserves economically feasible. The importance of natural gas is seen as likely to continue to expand over the coming years, and is expected to increase even further with environmental considerations, such as greenhouse gas emissions (MIT Energy Initiative, 2011).

Horizontal drilling and hydraulic fracturing producing natural gas from deposits such as the Marcellus Shale is making the US a net producer of natural gas, rather than being a net importer of natural gas (Natural Gas Weekly, July 19, 2010). In fact, studies have estimated the recoverable reserves in just the Marcellus Shale at over 489 trillion cubic feet (Tcf), making the Marcellus Shale the world's second-largest reserve, with only the South Pars field in Qatar and Iran being larger. With the Marcellus Shale deposits sitting deep below 95,000 square miles in New York, Pennsylvania, West Virginia, Ohio, Maryland and Virginia, this huge gas deposit is physically close to the population centers of the Mid-Atlantic and Northeast US. An existing and potential market of over 16 billion cubic feet (Bcf) of natural gas per day resides within a 200-mile radius of the Marcellus Shale deposits. The value of this reserve has been estimated to be over two trillion dollars at current natural gas prices (Considine, 2010).

The spread of Marcellus drilling in Pennsylvania has increased rapidly in recent years. Between 2005 and 2007, 155 wells were drilled in Pennsylvania. In 2008, this number more than doubled with 364 Marcellus wells drilled in Pennsylvania. Drilling almost doubled again in 2009 with 710 wells drilled in Pennsylvania (Considine, 2010). The number doubled again in 2010 with 1,454 Marcellus wells drilled in the Commonwealth (DEP 2011). By earlier this year, Pennsylvania Department of Environmental Protection records show that 2,773 wells have been drilled into the Marcellus Shale, and almost 6,500 permits have been issued, with projections suggesting that as many as 60,000 Marcellus wells will exist in Pennsylvania by 2030 (Hopey, 2011). The predicted natural gas output from shale is predicted to be higher than estimated earlier because of a significantly larger number of drilling rigs producing new wells and faster production times (i.e., more wells drilled per drilling rig resulting in faster cycle times to gas sales) (Pursell, 2010). In Pennsylvania by the middle of 2011, there are more than 1,600 Marcellus Shale wells in production, producing 432 billion cubic feet (Bcf) of natural gas during the first half of 2011 (Olson, 2011). Marcellus Shale well production in southwestern Pennsylvania alone, including Allegheny, Armstrong, Beaver, Butler, Fayette, Greene, Washington and Westmoreland counties, during the first six-months of 2011 increased 55 percent to 127 billion cubic feet (Litvak, 2011).

3 Economic Impact Estimates

Previous studies have examined the economic impact of exploration and production in the region. For example, Black, et al. (2005) found that an earlier coal boom spurred economic growth in the non-mining sectors, while the subsequent coal bust resulted in lower economic growth in the non-mining sectors of the region.

Marcellus spending in Pennsylvania rose from $3.2 billion during 2008 to over $4.5 billion during 2009 (Considine, 2010). As the number of Marcellus wells grow and the awareness of this industry becomes better understood (both for positive impacts and potentially negative impacts), there are beginning to be a number of studies that are examining the economic impact of the Marcellus Shale industry. Several of these studies address the economic impact of Marcellus Shale drilling (for example, Considine, 2010; Considine, Watson, and Blumsack, 2010; Barth, 2010, and The Perryman Group, 2008), while others examine the environmental and social impacts (Sample and Price, 2011, Ubinger, Walliser, Hall, and Oltmanns, 2010, U. S. Department of Energy, 2009).

3.1 Types of Economic Impact

The focus of this report is on the economic impact of Marcellus Shale development. There can be several types of economic impact from a particular economic activity. These can be categorized as direct effects, indirect effects, and induced effects, as shown in Figure 1.

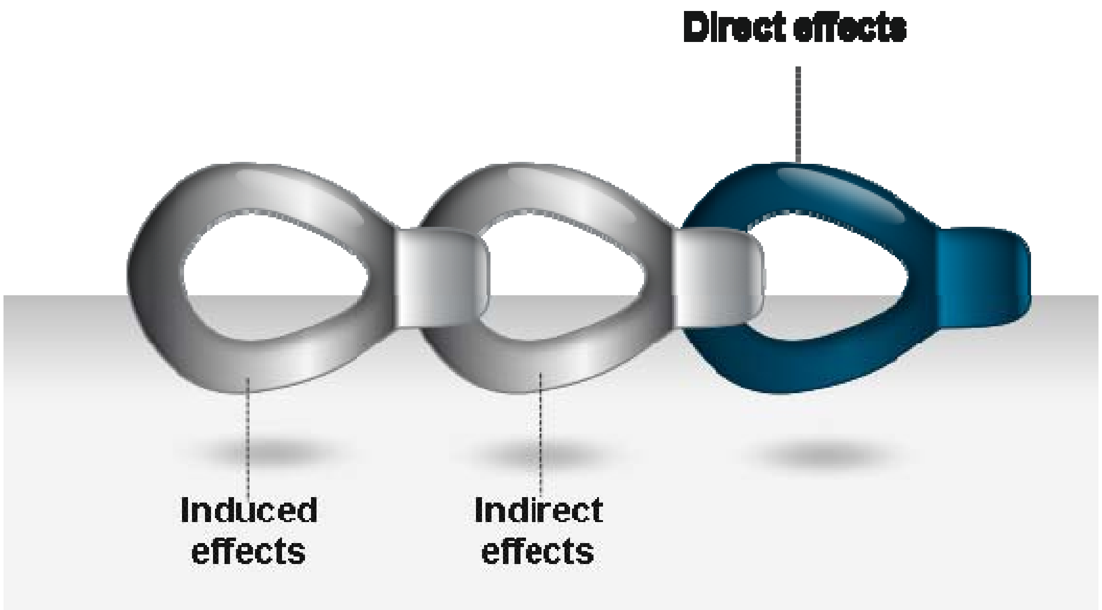


Figure 1 – Types of Economic impacts

3.2 Focus of this Study

The focus of this study is to understand the direct effects of a single Marcellus Shale well, developed using horizontal drilling and hydraulic fracturing, in Southwestern Pennsylvania. By using a single well as a standard unit of measure, the study gains breadth in its application to better understand the Marcellus Shale. This project sought to quantify the “business” factors of a single Marcellus Shale well value chain, by understanding the direct spending in the value chain of preparing, drilling, fracking and moving into production a single Marcellus Shale well site.

3.3 Other Economic Impacts

Beyond the direct spending impacts of Marcellus plays, there are additional economic impacts that come as a result of this spending. Kay argues that these impacts may be mixed; some will be winners, while others may not (Kay, 2011). These impacts extend throughout the entire supply and value chains of the Marcellus Shale wells, as explained by Kathryn Klaber (see Box 1).

Box 1: From an interview with Kathryn Klaber, president and executive director of the Marcellus Shale Coalition

"Q: Will most of the economic impact come from firms that are drilling?

A: It doesn't stop with the natural gas companies. There are law firms, accounting firms, small town grocers and dry cleaners all starting to realize -- in the areas where this is happening -- that there is business to be had and economic opportunities throughout the supply chain. "

Source: Pittsburgh Post-Gazette[1]

These additional impacts are comprised of two types of effects:

- Indirect effects
- Induced effects

As Figure 1 illustrates, the indirect effects are additional economic activity of the value chain network caused by the economic activity of the direct industry. The induced effects are additional economic activity of all other unrelated firms and households caused by the economic activity of the direct impacts and the indirect impacts. Examples of these ripple effects in Marcellus Shale economic activity are further described by Considine (2010), in his economic impact analysis for the American Petroleum Institute (see Box 2).

[1] Gannon, Joyce (January 24, 2010). Marcellus Shale Group Leader Excited: Talking With Kathryn Z. Klaber. *Pittsburgh Post-Gazette* (Pennsylvania), Sunday Two Star Edition, Business Section, pg. C-1.

Box 2: Explaining indirect and induced impacts in terms of Marcellus Shale

> "This spending by Marcellus producers will have ripple effects throughout the economy. For example, drilling companies hire trucking firms to haul pipe, water, and other materials to a well site. This trucking firm in turn must buy fuel and other supplies to supply these services and hire drivers to operate the trucks. The truck suppliers in turn acquire goods and services from other firms, such as repair shops, parts distributors, and other suppliers. So Marcellus investment sets off a business-to-business chain of spending throughout the economy. These economic impacts are known as *indirect* impacts. When the drivers go out and spend their paychecks, that spending stimulus sets in motion a similar chain reaction, known as *induced* impacts. For example, the driver spends his new income on fishing and hunting that stimulates local bait and tackle shops,convenience stores, and other establishments."

Source: Considine, 2010

The indirect and induced impact of the Marcellus Shale industry in Pennsylvania has been estimated to be almost as large as the direct spend. 2009 direct spend of the Marcellus Shale industry in Pennsylvania has been estimated as approximately $3.77 billion dollars, with additional indirect spending by other industries on goods and services totaling another $1.56 billion in impact. These direct and indirect impacts in 2009 generate additional income in the region, which then generates an induced impact of an additional $1.84 billion in additional goods and services. That is, for every $1 that the Marcellus industry spends in the state, $1.90 of total gross output or sales is generated within the Commonwealth (Considine, 2010).

3.4 Disclaimer

It is important to understand the current study in light of other economic impact studies and to understand how this study addresses (or does not address) limitations associated with these studies. A major criticism of studies of economic benefits addresses their limits (see Box 3).

Box 3: From a paper by Dr. Jannette M. Barth, principal of J.M. Barth & Associates, Inc., former Chief Economist, New York Metropolitan Transportation Authority and Consultant, Chase Econometrics/Interactive Data Corporation.

"The unsupported assumption of a net economic benefit from gas drilling in the Marcellus Shale is largely based on anecdotal experience and studies from other gas producing states."

Source: Barth, 2010

Crompton (1995) identified a number of common problems in the application of economic impact studies. Other criticisms of studies of economic impact studies include

- studies are biased (Barth, 2011),
- studies are dated (Barth, 2011),
- studies are seriously flawed (Barth, 2011),
- studies are sensitive to the region (Snowball, 2008), or are inapplicable to our region (Barth, 2011),
- studies fail to capture economic impacts that result from environmental damage or natural resource use (Barth, 2010),
- studies do not reveal their funding or data sources,
- studies have been funded primarily by industry (Barth 2011),
- studies rely on assumptions about rate, number, and geographic pattern of wells drilled (Kay, 2011),
- studies rely on assumptions "irrespective of how outrageous they may be" (Crompton, 2006),
- studies may address differing levels of economic activity, from individual facilities to groups of facilities and related operations, to these aggregated at the state, regional, or national levels (Bio Economic Research Associates, 2009),
- studies rely upon models (Kay, 2011),
- studies do not discuss the track record of the econometric model used, and
- studies ignore important and significant costs (Barth 2011).

As Crompton has observed, "Most economic impact studies are commissioned to legitimize a political position rather than to search for economic truth." (Crompton, 2006).

He goes on to conclude that the "motives of a study's sponsor invariably dictate the study's outcome." To overcome these common limitations of economic impact studies, this study was not sponsored or funded by exploration and production firms in the Marcellus Shale industry. As noted in the Front Matter, this study was supported by the University of Pittsburgh (Joseph M. Katz Graduate School of Business and the Institute for Entrepreneurial Excellence) and the Washington County Energy Partners, which is "a group of businesses, local politicians and economic development organizations" (Bradwell, 2010). Although this study was not funded by the industry, the EQT Corporation made access available to an active drilling site and personnel.

Many of the existing economic impact studies are based on input-output models (Miller and Blair, 2009, U. S. Department of Commerce, 1997). Barth (2010) makes the argument that the labor flows in Marcellus plays may not match the underlying assumptions in the input-output models.[2] Thus, to address this concern as well as Crompton's (1995) caveat that studies explicitly account for costs, the current study focuses on the direct economic impacts of Marcellus Shale drilling in a single Marcellus Shale well.

4 Lifecycle of a Marcellus Shale Wellhead

4.1 Phases of the lifecycle

The development of a wellhead typically progresses through a lifecycle consisting of multiple phases, with each phase composed of multiple steps.[3] The steps within each

[2] See also Section 6.3 for data on workforce development in Marcellus Shale that further explains this objection.

[3] More details on each step can be found at Horizontal Drilling Animation (Haynesville Shale Education Center, Lousiana Oil and Gas Association), available at http://www.loga.la/drilling.html; and in U. S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (2009). *Modern Shale Gas Development in the United States: A Primer*. Morgantown, WV: National Energy Technology Laboratory, Strategic Center for Natural Gas and Oil, available at http://www.dep.state.pa.us/dep/deputate/minres/oilgas/US_Dept_Energy_Report_Shale_Gas_Primer_2009.pdf

phase could vary across sites, depending on factors, such as the current drilling or leasing status of the site and its geography. Lifecycle phases of a typical wellhead are:

- Phase 1 – Mineral Leasing/Acquisition and Permitting
- Phase 2 – Site Construction
- Phase 3 – Drilling
- Phase 4 – Hydraulic Fracturing
- Phase 5 – Completion
- Phase 6 – Production
- Phase 7 – Workovers
- Phase 8 – Plugging and Abandonment / Reclamation

Figure 2 provides a visual depiction of these phases and key steps. A visual animation of the horizontal drilling and fracking process[4] can help to explain this process. An enormous amount and variety of inputs from various sources come together for one drill site. The value chain begins with site preparation and continues all the way through post-production. The site needs to be levelled, with proper entrance and exit roads for the equipment. Then all the actual drilling equipment is put into place, which may require the rental of the equipment, with truckloads transporting the equipment to the site. Before drilling, a sustainment infrastructure needs to be put in place. This includes generators to provide power to the entire site, which use non-road diesel that needs to be transported on-site, and may include living quarters for the drilling workers. Security measures may be put into place. All water used throughout the process either needs to be piped or trucked on-site. Then when the drilling starts, all of the ingredients for the lubricating "mud" need to be bought and transported, including water, salt and a mix of chemicals. Then the mud is processed and most of it is recycled and drilling chips separated and trucked away. After the vertical drilling is complete, concrete filler is put in place to keep the integrity of the hole, protecting both the well itself and the environment that it traverses. Then the horizontal drilling process starts, which also requires the lubricating "mud." When complete, the horizontal section gets the concrete as well. Next in the value chain is the shale fracturing process. This process requires the charges that will be put

[4] This visual animation is available at http://www.loga.la/drilling.html.

underground as well as the fracturing fluid which consists of water, sand and another mix of chemicals and additives. The outflow of fracturing fluid also needs to be either held temporarily on-site and transported off-site, or immediately transported. After this process, the equipment is removed and the piping infrastructure is put into place along with a permanent well head or “Christmas tree”.

This report addresses the direct economic effects of Phases 1 through 6 of a Marcellus Shale well. Phase 7, occurring throughout the working life of a producing well, and Phase 8, which occurs at the end of the life of a well site, are not included in our analysis. Given the expected productive life of a well spanning over many years, these costs will indeed have continuing economic benefit to the region, but are not addressed in this report. Each of these phases in developing a producing Marcellus Shale horizontal well is briefly described in the following sections. More details on each step can be found in Horizontal Drilling Animation (Louisiana Oil and Gas Association, 2008), or other reports (U. S. Department of Energy, 2009).

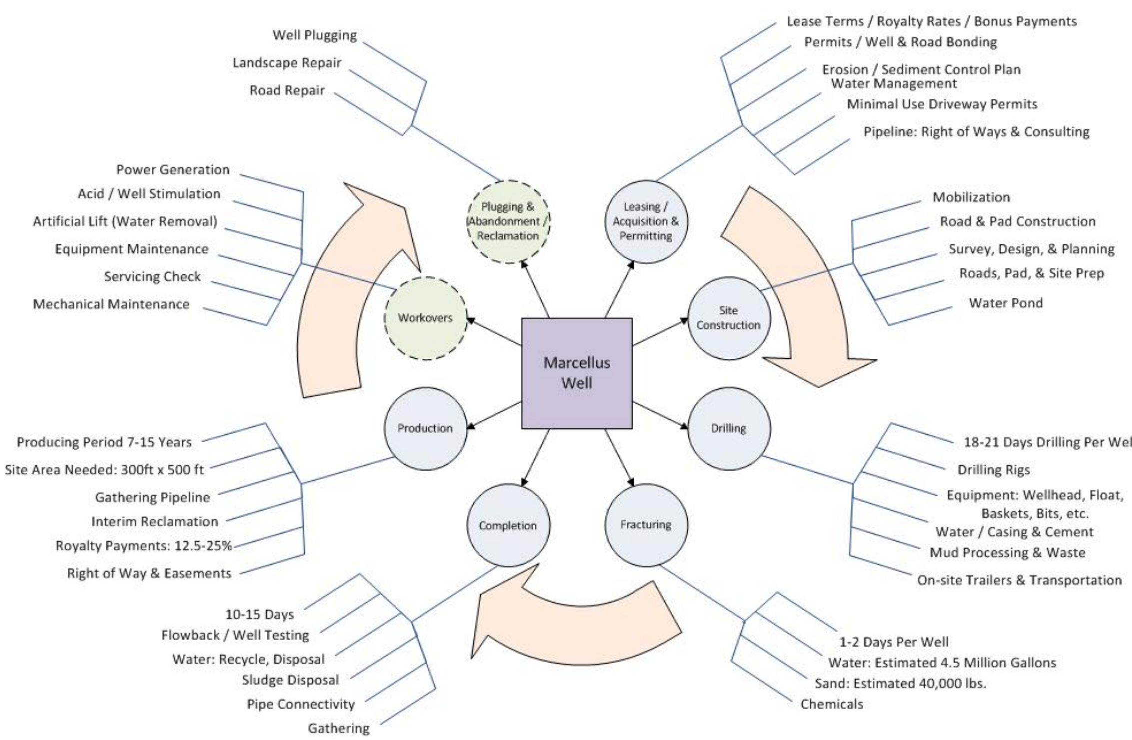


Figure 2 - Phases and Key Steps in Developing a Marcellus Shale Well Site

4.2 Phase 1 – Mineral Leasing/Acquisition and Permitting

When analyzing the total cost of drilling a gas well, two preliminary steps must be considered: mineral leasing and acquisition, and permitting. These steps are critical to the establishment of a well and can contribute significantly to overall cost.

Exploration and production companies, or landmen acting for them, must approach and negotiate with landowners for mineral rights leasing (see Table 1 below for examples of Standard Terms and Conditions). This process will often start with the largest tract of land, moving on until sufficient rights are acquired for effective production. This study assumes that 320 acres is the minimum acreage to permit, with 640 acres (1 square mile) being the minimum optimal size. Adjacent properties may also be placed under license, as surface/non-surface leases allow placement of the pad site location on property or only the access to minerals underneath.

Second, the permitting stage requires the satisfactory filing/obtaining of state and local permits and posting of necessary bonds to allow for site preparation to begin.

4.3 Phase 2 – Site Construction

The second phase, Site Construction, involves the design and layout of the well site for the construction of the Road and Pad, or "Staking the Well." The steps involved in this activity include, among other things: survey, site design and layout, water planning (i.e., planning for water ponds, water supplies via trucks or pipeline), construction of access roads, road and pad construction (i.e., staking the well), placement of on-site trailers, construction of water storage or pits, and erosion control.

Table 1 - Standard Terms and Conditions

Term	Notes	Term	Notes
Term	Primary / Secondary	**Wells**	Disposal and Injection
Royalties	-	**Pooling**	-
Delay Rentals	Paid-up vs. Annual	**Pugh Clause**	Vertical and Horizontal Depth
Shut-in	Price, Duration	**Depth Limitation**	Marcellus or Other Strata
Force Majeure	-	**Taxes**	Severance, Ad Valorem
Surface Use / Non-Surface	Limited Use, Equipment Limitations, Location, Road Widths, Pipelines	**Surrender and Termination**	Right to Surrender, Equipment Removal, Termination/Survival of Easements, Recording
Surface Damages	-	**Implied Duties**	Protect from Drainage, etc.
Easements	Pipelines, Access Roads, etc.	**Audit**	-
Water Quality	Pre-Drill Testing, Replacement	**Dispute Resolution**	ADR, Jurisdiction
Water Use	Ponds, Streams, Wells, etc	**Other**	Needs of Lessee / Lessor
Gas Storage	-	**-**	-

4.4 Phase 3 – Drilling

The drilling phase may take 23-35 days per well, including five days for mobilization and 18-21 days for drilling itself. This phase requires myriad pieces of equipment supporting drilling rigs, power generation, processing and disposal of liquid and solid waste (both chips from drilling operation and drilling mud returned with the chips), and the wellhead equipment and the Bottom Hole Assembly (BHA).

While this study focuses on a single well with a on a pad in a site, it is possible to place up to six wells per drilling pad, with each well having one or more horizontal laterals.

4.5 Phase 4 – Hydraulic Fracturing

In the process of hydraulic fracturing, or "fracking," a fracking solution is injected into a well under high pressure. Water, along with additives, fracture the shale rock, while sand props open the fractures, allowing the natural gas to flow (Harper and Kostelnik).

4.6 Phase 5 – Completion

Completion of a gas well, over 10-15 days, involves the processes of recapturing flowback and well testing, water recycling (and/or disposal), flare (if needed), and the installation of a "Christmas Tree."

4.7 Phase 6 – Production

For the purposes of this study, the production stage only covers to the gathering system and pipeline. Processing of the natural gas (and potentially other products) are outside the scope of this analysis. There are, however, several requirements within our scope that will be necessary over the 7-15 year lifespan of a well. Costs will include one-time costs such as the finishing off the pad area (typically 300ft x 500ft), the gathering pipeline, and interim reclamation costs, such as erosion control, landscape repair, and road repair. Ongoing payments relating to production are royalty payments to the lessor.

4.8 Phase 7 – Workovers

Workovers, as part of the ongoing operation of the well, rather than its initial development, are not included in our economic impact analysis. Workover activities could include power generation, such as solar power for the Christmas tree or an onsite generator, additional well stimulation (fracking), equipment maintenance and servicing.

4.9 Phase 8 – Plugging and Abandonment / Reclamation

Activities associated with plugging and abandonment of the well and reclamation of the site, such as landscape or road repair, are not addressed within the scope of our economic analysis.

5 Value Chain of a Marcellus Shale Wellhead

Building on the preceding lifecycle, this section summarizes the value chain of a Marcellus Shale wellhead by examining the spend associated with a typical wellhead in Southwestern Pennsylvania. Starting with the general lifecycle flow, and detailing specific steps within the lifecycle and their costs, we are able to develop a view of the value chain of a typical Marcellus Shale wellhead. The next section addresses limitations of our analysis, while the following sections describe in some detail the process of creating and moving into production a Marcellus Shale well, and its associated value chain.

5.1 Limitations

Uniqueness of Each Well

Each well is unique. The physical location for each is different from the next. The geology underneath the well site may vary, as the Shale depths and thickness vary and there may be water sources or pre-existing mines beneath the property. The distance to water supplies, essential for drilling and fracking, will vary site to site. Some can be supplied by existing water supplies and piping, others may require water to be trucked in. Distance to existing roads will vary, depending on the site selected by the developer for the vertical shaft. Setting up a gas well is completely different with every new well and it is not possible to generalize the required effort using a simplistic formula. The steps are the same, but the detailed economics and costs behind them can range widely, depending on the characteristics of the well and the site. This is not only true within the industry, but also across the sites being developed by a single company.

Wellhead Characteristics

Our typical wellhead has the following characteristics, some of which could vary across sites and geography. These assumed characteristics allow us to develop a cost model of the typical wellhead. Characteristics of our typical wellhead are:

- Located in Southwestern Pennsylvania, drilling into the Marcellus Shale deposit
- Vertical shaft drilled to kick-off point at approximately 6,000 feet
- Single horizontal lateral, of approximately 4,000 feet
- 11,000 foot total measured depth (TMD)
- A well site of 300 ft. by 500 ft. = 3.5 Acres

These characteristics are reflected in the value chain summarized in the following Sections, which describe each phase of the lifecycle and the direct economic impact of each phase of the Marcellus Shale extraction lifecycle.

Proprietary Data

Numerous data sources were used for the development of this report. These include laws and regulations, public records, published literature, observations and interviews from site visits to Marcellus wellheads, numerous telephone and email interviews with a number of individuals and organizations involved in the industry.

A key source of developing the research team's understanding of the Marcellus drilling and fracking process was a site visit, made by the entire research project team, to an in-process well site in Washington County, PA. Shaun Seydor, Director of PantherlabWorks, and Pitt Business Professor Bill Hefley, PhD, led a Pitt student delegation tour of this Marcellus Shale well site. Access to the well site and personnel were provided by EQT to help the research team better understand the supply chain of a single Marcellus Shale well. The delegation, consisting of both an undergraduate Business class and a Katz MBA class, had an all access tour of an operating drilling site, on Friday, March 25th, 2011. Figure 3 depicts the delegation at an active drilling site.

Activities such as these are one example of Pitt Business' ongoing commitment to experience-based learning.[5] These project courses are an integral portion of the Undergraduate Certificate in Supply Chain Management (CSCM)[6] and the MBA program's Global Supply Chain Management Certificate[7] at Pitt Business.

Figure 3 – University of Pittsburgh Project Team Visiting a Marcellus Shale Well Site

[5] Experience-Based Learning, http://www.business.pitt.edu/about/initiatives/experience-based-learning.php, Accessed 10 August 2011.

[6] Certificate in Supply Chain Management, http://www.business.pitt.edu/cba/academics/supply-chain-certificate.php, Accessed 10 August 2011.

[7] Global Supply Chain Management Certificate, http://www.business.pitt.edu/katz/mba/academics/certificates/supplychain.php, Accessed 10 August 2011.

5.2 Mineral Leasing/Acquisition and Permitting

5.2.1 Leasing/Acquisition

The acquisition of mineral rights and development of a proposed unit is the first step in the development of the Marcellus Shale drilling process. The leasing and acquisition stage begins with the assumption that adequate and appropriate land has been identified. Geological exploration and its associated costs are therefore excluded from our analysis in this study.

Landowners, also known as lessors, will lease their respective mineral rights, specifically the oil and gas, underneath the property of which they have ownership. The primary benefits that can be recognized from the signing of a lease are in the form of a signing bonus, also known as a paid-up lease, and royalty rates.

Landmen have the principal responsibility of approaching and acquiring landowner's mineral rights by leasing the parcel with a number of negotiable terms to be considered as a binding agreement. The landmen typically represent an operating company, whereas the operating company is known as the lessee. The landmen must establish a unit that contains a minimum of 640 acres (1 square mile) of land that contains adjacent parcels in order to reduce the amount of petitioning rights to gain the privilege of drilling commencement. The analysis that covers the cost of acquisition will be based on this amount of acreage. In order to determine the actual mineral interest of property, title checks are done to determine that the correct parties have been signed and are able to release their rights for a specified time period.

The landowner's greatest incentives come from a few different contingencies of the lease. The most important of the leasing conditions, which have been mentioned above, are that of the signing bonus and the royalty rates. The signing bonus is the "short-term" amount that entices owners to sign the rights of their land to an operator for a certain time period. The signing bonus is negotiated separately from the royalty rate, and in most instances, is the only driving force for the parcel owner to sign so that an instant profit can be seen from the arrangement. There is a relatively high possibility that a leased property will not see a completed well due to the location or inability to establish a unit, or for other active wells or mineral reservations in the area. For this reason, the signing bonus becomes the most important factor in the negotiations due to the possibility of it being the only source of revenue that will be seen. The average signing bonus is found to be $2700/acre (www.pagaslease.com[8]). Using this estimate, the overall cost of signing bonus (640 acre unit) is $1,728,000. This is based upon the fact that all landowners that have been pooled into the unit have been offered the same amounts. This amount, as well as others, is highly variable, and the breakdown of the average, best-case, and worst- case scenarios can be found in the attached exhibits 1-3. The variability is due to a number of reasons, including, but not limited to, the owners ability to negotiate, the geological benefit of the land, economic impact, acreage size, and surrounding interest. The discussion of the costs for this will be based on the average amounts, as the other two represent extreme cases which are highly unlikely to happen. The actual payment of the signing bonus is paid “up front” in order for the operating company to have the ability to drill on or under the property for a certain time period. The average lease is estimated to be a 5 year primary term. In addition, the operating company may have the ability to extend the lease for an additional 5 year term, at which time the property owner will receive the signing bonus again. This will then double the amount of cost for each lease that needs to be renewed within the unit to be established. The reason for this is that if the unit has not been developed within the first five years, that the lease extension will grant them the ability, if it so chooses to, to complete the unit and drill during the extended lease terms.

The royalty rate is a percentage of the produced amount based on the completed well’s output. For example, in a 640 acre unit (1 square mile), suppose a landowner owns 320 acres of the established unit. If the royalty rate is agreed to be 1/8, or 12.5%, then the profitability that the landowner would recognize would be 12.5% of ½ of the total amount produced from the wellhead. The remaining 320 acres will be dispersed accordingly with

[8] The Natural Gas Forum for Landowners website (www.pagaslease.com) serves as an exchange of information about companies and the associated rates of signing bonuses for the Southwestern Pennsylvania region.

regards to the remaining property owner's respective royalty rates and acreage in relation to the total sum of the unit. The royalty rate is viewed as the long-term financial reason for leasing with an operator. The amount of royalties that landowners are capable of receiving can exceed hundreds of thousands of dollars per year based on the pre-negotiated royalty rate and size of the property. The royalty rate is considered the most important part of the contractual agreement between the lessor and lessee. The estimations of the amounts of royalty rates will be discussed in another section of the analysis, due to the actual payments being generated from a producing well, which is outside the scope of this portion of the analysis.

Another area of concern is the type of lease that is signed. Landowners have the ability to lease a surface or non-surface lease. The surface lease allows the operating company the access to have the pad site location to be on their property. The non-surface lease allows the operator to only drill underneath the property to access the oil and gas. This is achieved through the pad site location being within the capable distance of a drilled lateral. Mainly, non-surface leases are paid a lower amount, due to the restricted access, as well as many times being too small of an area to be considered for a pad site location. The parcel owners that do sign a surface lease, typically greater than 5 acres for a pad site to be located, are often times given additional payments based on the pad site being located on their property. Average amounts of bonuses are estimated to be $10,000 if their property is selected to be utilized for the drilling location (Title Abstractor "C", personal communication, April 12, 2011).

In addition to the above pad site location bonus, landowners often times are incentivized through a timber clause. In this clause, the landowner may receive money through the harvesting and sale of any timber that is required to be removed in order to construct the pad site location. The operating company will pay the parcel owner the market price that the timber can be sold based on the amount that is provided.

Shut in fees are the last aspect of the cost of leasing parcels. Although the shut in fees typically are not of concern, and for this reason have not been estimated to be a cost of acquisition, are able to generate a cost to the operator. Shut-in fees are a predetermined amount that is paid to the landowner in the event that the well is stopped from producing due to any number of reasons on the operator's behalf. In the event that production is available and is stopped, the landowner will receive an amount, which is typically minimal, to be paid on a daily, monthly, or annual basis. Shut-in fees are typically not of concern, as the Marcellus Shale operating companies fully recognize the need to produce and sell the natural gas in order to profit from its capital requirements.

In order to establish a unit of land to be capable of drilling, the landmen approach and negotiate the stipulations of the lease on a case-by-case scenario. The landmen are often times hired by the operating companies as independent contractors that are paid a day rate for their services. The average amount of time that it takes for a single landman to develop a unit for drilling purposes is estimated to be around one and a half years, or 375 working days (Landman, personal communication, April 17, 2011). At an average day rate of $300/day, the associated leasing labor is estimated to be $112,500. Again, these numbers are an average, and labor rates can vary from $150/day and up to $450/day, not including per-diems and paid mileage (Landman, personal communication, April 17, 2011). The time required is also highly variable, with a best-case scenario of 9 months, and a worst-case of 5 years. The amount of surrounding acreage and the willingness of the mineral owners is highly correlated to this cost. The amount of parcels that are involved in the pooling of a unit fluctuates from a minimal number, such as 5, to as many as 500, depending on acreage sizes of surrounding property owners. The greater the amount of parcels that needs to be approached and negotiated becomes highly involved and can delay the process for years. For the purpose of generating an average number of parcels, 50 properties are considered as a benchmark (Landman, personal communication, April 17, 2011).

After a lease is signed, the determination of the mineral interest is researched. The parcel of land is researched initially by the landman to conduct a due-diligence research on the property. This entails running the title back to the approximate time between 1850 and 1880. The date that it is targeted to be researched to is determined by the initial drilling and exploration that Pennsylvania has been exposed to. The first wells were drilled around this time and can affect the ownership of parcels to current date. In order to determine the interest, a few steps are taken at the county courthouse's recorder of deeds office in which the parcel is located. The landman will first check the title to be certain that none of the following apply to the property:

- Prior oil and gas reservation in deed history. In this instance, historic evidence states that a landowner in prior ownership reserved the oil and gas rights when the land was sold to the grantee. In this scenario, the reservation holder must be approached to conduct leasing practices. Often times, the reservation is extremely old, i.e. greater than 100 years ago, and the current landowners are able to appeal to courts their ability to regain the rights to the oil and gas if no production or outstanding lease is active.
- Held By Production (HBP) - In this case, there is an active well on or nearby the land that is classifying it as unable to be leased until the active well is either negotiated for Marcellus Shale rights (depth severance), the well is bought by the operator, or the well stops production.
- Leased property - In the modern day boom of the Marcellus Shale, many landowners have been leased already, and are not able to negotiate new terms as they are contractually bound to the lease that they have entered. Also, leases prior to the Marcellus Shale exploration can be problematic, and an active lease term will deny the landowner access to lease with any other operator. In some instances, leased land can be negotiated between parties to allow a depth severance of the parcel at hand. In this scenario, the lease that the Marcellus Shale operator is interested in leasing can be done in conjunction with the interest of the current lease owner in accordance with certain depth limitations. This will allow for the drilling of multiple layers of gas, such as shallow coal-bed methane, as well as the deep horizontal wells found in the Marcellus. This principle can also be applied to an area that is involved as HBP.

The landman's labor behind this initial research is estimated to take on average 1-2 days per parcel. This number has been taken into consideration within the complete timeframe of a landman's responsibilities within the cost analysis. This is highly variable as well, regarding the complexity of potential title problematic situations. Once the mineral ownership is determined, and a parcel owner does in fact own the interest in the minerals underlying their property, the negotiated bonus payment is given. If the owner does not own the interest for any of the above mentioned reasons, then the lease is voided, and the correct owner of the mineral rights, and associated heirs, needs to be determined and approached to possible leasing abilities.

After the preliminary title check is done and approved, the lease is taken to the county courthouse and filed to be recorded into the system of publicly available information. This is estimated to be $78.50/lease.[9] Based on a unit size of 50 parcels, the amount is estimated to be just under $4000/unit. The recording of the lease document allows other companies to realize the ownership of that lease for further research and unitization pursuance.

Following the preliminary check by the landman, the title will then be moved into a more in-depth approach to conduct a complete record of research, known as abstracting. The parcels are abstracted when the completed land is pooled together and is ready to be constructed. Prior to the construction, abstractors are utilized in order to re-research the title, and check the landman's title for errors. In addition to rerunning the title, the abstractors must check all heirs, right-of-ways, wills, unrelated mineral interest conveyances, and a number of other areas that complete a comprehensive title check. Each parcel involved in the unit must be conducted and approved before the commencement of a pad site can begin. The estimated average time to conduct an abstracted title averages 10 working days, with a best-case scenario of 5 days, and worst-case scenario of 6 months (Title Abstractor "B", personal communication, April 4, 2011). The title researchers are typically sourced and paid as independent contractors. The typical day rate is averaged to the amount of $275/day, with variances of $150-$400/day seen (Title Abstractor "A", personal communication, April 4, 2011). This is highly variable for the associated contractor's experience and paying company involved.

[9] According to the Allegheny County website, http://www.alleghenycounty.us/re/fees.aspx

The amount of parcels that are in the developed unit is what consumes most of the abstracting costs. With the number of parcels averaging 50 in a given unit, the average day rate of $275 is estimated to have an overall cost of $137,500/unit (Title Abstractor "C", personal communication, April 12, 2011). This number is extremely susceptible to fluctuation based on the complexity of the title and the number of parcels in a unit. The best-case scenario is based on a 5 parcel unit at $150/day rate, and each parcel requiring 5 days of working time, equaling $3,750 of labor. The worst case, on the other end of the spectrum, is based on 250 parcels being evaluated at $400/day and 6 months working time. This translates to an astronomical increase of $12M/unit. At this rate, the operating company would not benefit from a profitable situation from the well's production. Also, the associated average costs do not reflect the possible per-diems and paid mileage that is given by the operating company. In this extreme event, the likelihood of these possible delays are highly minimized due to the nature of abstracting efficiencies of common title and ownership being met from the preliminary title. This is through the first parcel being investigated and expanded and encompassing surrounding parcels through the historic relation of increasing parcel size before being subdivided. These additional costs have not been added into the average cost due to the variance and availability of the resources from one organization to the next.

The last part of the acquisition cost involves the title research and acquisition known as curative title and development. This department will oversee any missed research or acquisition parameters that are deemed necessary by legal entities before drilling can commence. The curative team may, for example, need to find and sign additional members of a family in order to have the actual leasing rights. This is just one of many examples that the curative member may be required to do.

The average amount of curative work needed to be done for each unit is estimated to be 25 working days (Title Agent "A", personal communication, April 14, 2011). The variability of this may differ from 10 working days (2 weeks) up to 120 days (6 months). The average labor rate is based on an independent contractor day rate as well, with average rates of $275/day being an estimated average (Title Agent "B", personal communication, April 19, 2011). The rate fluctuates to include variances of the same amounts of the abstracting department, being $150-400/day. Total average cost per unit for curative research and procurement is estimated to be $6,875.

In the end, the complete cost of the leasing and associated labor costs generated from landman and title research is estimated to be approximately $2.2 million/640 acre unit. The amount of variability depending on numerous conditions and circumstances reflects a best-case scenario of approximately $100,000, and a worst-case scenario of approximately $20.7 Million. The amount of complexity and parcel acreage, as well as landowner's willingness to lease, can prove to generate numbers at any point within these scenarios.

The following Tables depict the average (Table 2), best-case (Table 3), and worst-case (Table 4) scenarios for overall costs of land acquisition.

Table 2 - Average costs of land acquisition

Acquisition/Leasing	based off 640 acre site	1 year = 250 days	
Parcels in pooled unit=	50		
Labor Costs	**Avg. Time (days per padsite)**	**Rate (avg day rate)**	**Total**
Leasing			
Landman	375	$ 300.00	$ 112,500
Title research			
Abstract (*per unit*)	10	$ 275.00	$ 137,500
Curative (*per unit*)	25	$ 275.00	$ 6,875
Subtotal (subject to # of parcels in unit)			***$ 256,875***
Leasing Costs (paid-up lease)	**Avg. Cost**	**Amount**	**Total**
Signing bonus/acre	2700	640	$ 1,728,000
Bonus/padsite location	10000	1	$ 10,000
shut-in (*typically not paid*)	10	640	$ 6,400
lease filing at courthouse (*per parcel*)	78.5	50	$ 3,925
Subtotal (subject to # of parcels in unit)			***$ 1,934,250***
Total			**$ 2,191,125**

Table 3 - Best-case scenario for land acquisition

Parcels in pooled unit=	5		
Labor Costs	**Best Time (days per padsite)**	**Rate (lowest day rate)**	**Total**
Leasing			
Landman	188	$ 150.00	$ 28,200
Title research			
Abstract (*per unit*)	5	$ 150.00	$ 3,750
Curative (*per unit*)	10	$ 150.00	$ 1,500
Subtotal (subject to # of parcels in unit)			***$ 33,450***
Leasing Costs (paid-up lease)	**Lowest Cost**	**Amount**	**Total**
Signing bonus/acre	100	640	$ 64,000
Bonus/padsite location	0	1	$ -
shut-in (*typically not paid*)	10	640	$ 6,400
lease filing at courthouse (*per parcel*)	78.5	5	$ 393
Subtotal (subject to # of parcels in unit)			***$ 65,963***
Total			**$ 99,413**

Table 4 - Worst-case scenario for land acquisition

Parcels in pooled unit=	250		
Labor Costs	Worst Time (days per padsite)	Rate (highest day rate)	Total
Leasing			
Landman	1250	$ 450.00	$ 562,500
Title research			
Abstract (*per unit*)	120	$ 400.00	$ 12,000,000
Curative (*per unit*)	120	$ 400.00	$ 48,000
Subtotal (*subject to # of parcels in unit* ***)***			***$ 12,610,500***
Leasing Costs (paid-up lease)	**Highest Cost**	**Amount**	**Total**
Signing bonus/acre	5000	640	$ 3,200,000
Bonus/padsite location	20000	1	$ 20,000
shut-in (*typically not paid*)	10	640	$ 6,400
lease filing at courthouse (*per parcel*)	78.5	250	$ 19,625
Subtotal (*subject to # of parcels in unit* ***)***			***$ 8,126,250***
Total			**$ 20,736,750**

5.2.2 Permitting

Permit Fee

25 PA Code § 78.19 Permit application fee schedule[10] defines the fee structure for obtaining the required state permit to drill a well. Using our assumed well with a total measured depth of 11,000 feet, the permit cost is $3,050. Using a more typical well site with vertical depth of 8,000 feet and 3 horizontal bores of 4,500 feet total permit cost is $5,150.

[10] The Pennsylvania Code is available online at http://www.pacode.com/secure/browse.asp

Total permit application costs for Marcellus Shale wells include three components: permit application, abandon well surcharge, and orphan well surcharge. When drilling a gas well in Pennsylvania, the well operator must obtain a well permit from the Department of Environmental Protection (DEP). The permit application must show the location of the well, proximity to coal seams, and distances from surface waters and water supplies. Technical staff in DEP's Regional Offices reviews the permit application to determine whether the proposed well would cause environmental impacts and conflict with coal mine operations.

To address additional environmental considerations associated with development of shale, the DEP developed an addendum specifically for shale gas well development. The DEP expends considerable staff resources to review the additional information in the Marcellus Shale Addendum because the review includes several water quality and quantity issues not normally associated with gas well permit application reviews.

Effective April 18, 2009, the application fee for well permits for shale natural gas wells follows a sliding scale based on well bore length and type.[11] Any application received on or after April 18, 2009, must include the new application fee in addition to the surcharge fees for abandoned wells and orphan wells.

The permit fee is based on the anticipated total length of the well bore in feet, which is the Total Measured Depth (TMD) for horizontal wells. If the well is drilled longer than what was applied for in the application, the applicant will be required to pay the difference between the amount paid on the original application plus 10% on the amount required by the completed well bore length. The surcharge can be avoided by amending the original permit and paying an additional permit fee. A refund is not issued for under-drilling the length of a permit.

[11] 25 PA Code § 78.19. Permit application fee schedule. http://www.pacode.com/secure/data/025/chapter78/s78.19.html

The permit fees for the gas wells were established to cover program costs including hiring additional staff in Meadville, Pittsburgh, and Williamsport to process permits and better monitor drilling activities statewide.

In accordance with the Pennsylvania Oil and Gas Act, Marcellus Shale wells are "subject to orphan and abandoned well surcharges" of $200 and $50 per well respectively. These surcharges are in addition to the gas well permit fees and will be paid into the Orphan Well Plugging and Abandoned Well Plugging Funds.

Table 5 - Permit fees

Permit fee	$4,900
Orphan well surcharge	$200
Abandoned well surcharge	$50
Total State Permit (drilling) Fees	**$5,150**

Well Bonding

Gas wells drilled in Pennsylvania after April 17, 1985 are required to be bonded, according to 25 PA Code § 78.310 Well Bonding. The bond is a financial incentive to ensure that the operator will perform the drilling operations, address any water supply problems the drilling activity may cause, reclaim the well site, and properly plug the well at the end of the wells useful life in accordance with their permit. The bond permit for a single well is $2,500; a blanket bond to cover any number of wells is $25,000.

Erosion and Sedimentation Control

25 PA Code § 102.6 addresses fees for erosion and sediment control. Fees are set at $1,500 plus $100 per acre disturbed. Thus, assuming a well site of 300 ft. by 500 ft., or 3.5 Acres, results in a fee cost equaling $1,900.

The code requires all projects that disturb earth in the state to develop an erosion and sediment pollution control plan and implement best management practices for the control of sediment pollution during drilling. The Erosion and Sedimentation Control Program ensures that proper site development practices are employed for land development.

Generally, two different kinds of water use have to be differentiated in the context of a Marcellus Shale well. First, there is water for drilling. Secondly, the fracking process requires a significant amount of water. Water is obtained from several sources, including surface water locations such as rivers, streams and large lakes, and groundwater wells. All of these sources must be approved by the Pennsylvania Department of Environmental Protection (PADEP) and Susquehanna River Basin Commission (SRBC), if applicable. Gas companies also have water sharing agreements with other operators to reduce the industry impact[12].

Since August 14, 2008, gas companies are required by the Susquehanna River Basin Commision to seek permission to withdraw or use water to establish wells in the Marcellus Shale in the Susquehanna watershed. Without approval by the commission, gas companies are not allowed to start gas well construction, drilling or hydrofracturing (Abdalla and Drohan, 2010).

In addition to this, the Water Resources Planning Act (Act 220 of 2002) and the regulations at 25 Pa. Code Chapter 110 presuppose that water withdrawals that exceed 10,000 gallons per day for any average thirty-day period are registered with the Pennsylvania DEP. Irrespective of the basin location of the water sources, the DEP demands an approved water management plan in the context of the gas well permit. With this requirement the DEP intends to register all water sources used in the fracking process for each Marcellus Shale well in the Commonwealth. The water management plan incorporates other information regarding the sources of the water that are used during the fracking process and the expected impacts on the water resources from the withdrawals. Also, a proof of approval by the respective river basin commission has to be provided (Abdalla and Drohan, 2010).

[12] Source: EQT

Water Quality Management Permit

Fees for water quality management permits are addressed in 25 PA Code § 91.22. A Marcellus Shale gas well permit application includes an addendum for a water management plan that the operator must also submit to the DEP. The addendum is required due to the volume of water that is used in the hydraulic fracturing of the shale. The permit review evaluates the water intake information during the fracking process, in addition to the management, treatment, and discharge of the wastewater. The review of the water management plan requires additional DEP staff time because it requires staff to evaluate water intake information associated with the hydraulic fracturing of the shale, including review of the management, treatment and discharge of the wastewater. The cost of this additional permit is $500.

When a well site is larger than five acres, a storm water management permit must be obtained. This "disturbed area" includes well sites, associated roads, pipelines, and storage areas to be constructed. The affected surface landowner and coalmine operator have the opportunity to file an objection about the location of the well. If DEP's permitting staff finds that no adverse impacts would result, the operator will receive a permit to drill the well.

Road Bond

67 PA Code § 189.4 establishes a road bond for overweight vehicles, resulting in bond charges of $12,500 per road mile. Road bonds for overweight vehicles can be provided in several forms: performance bonds issued by an insurance company, certified check, cashier's check, irrevocable letter of credit, or self-bonding if qualifications are met. Amounts are based on the type of roadway traveled and the maintenance required to repair the road due to the overweight vehicle. They are set in regulation at $6,000/mile for unpaved roadways, $12,500/mile for paved roadways, and $50,000/mile for paved roadways that are reverted back to unpaved conditions. A hauler traveling over numerous posted roads under the control of one owner can provide $10,000 security for each owner.

The bond owner is responsible for the restoration of any damage before the agreement can be terminated and the bond released. The bond owner can make the repairs themselves or the posting authority can make the repairs and bill the bond owner. Bond owners are encouraged to make the repairs to better control repair costs.

If more than one bond owner uses the roads, they can pool resources and reach an agreement on how restoration responsibilities will be divided. If an agreement cannot be reached, the posting authority will determine the division of restoration responsibility. In either case, each bond owner must execute an agreement for the division of responsibilities.

Enforcement of weight limits on state owned roads are handled by the state police and PENNDOT's Motor Carrier Enforcement Teams. They also assist local governments with enforcement on local roadways when possible. Penalties for traffic condition violations range from $25 to $100 and overweight violations range from $150 plus $150 for each 500 pounds in excess of 3,000 pounds over the maximum allowable weight for violations dependent upon the condition of the roadway or bridge.

Driveway permits

67 Pa. Code § 441.4 establishes fees for minimal use driveway permits of $25.00. The ability of a driveway to safely and efficiently function as an integral component of a highway system requires that its design and construction be based on the amount and type of traffic that it is expected to serve and the type and character of roadway which it accesses. Driveways are categorized into four classifications, based on the amount of traffic they are expected to serve. For purposes of a gas well, the minimum use driveway is applicable. Not more than 25 vehicles per day can use a minimum use driveway.

Table 6 - Permit fees and bonds required

25 PA Code § 78.19 State Permit (drilling) Fees	$5,150	
25 PA Code § 78.310 Well Bonding	$2,500	
25 PA Code § 102.6 Erosion, sediment control plan	$1,900	
25 PA Code § 91.22 Water Management	$500	
67 Pa. Code § 441.4 Minimal use driveway permits	$25	
Total	$10,075	
Plus		
67 PA Code § 189.4 Road Bond for overweight vehicles	$12,500	per mile

5.3 Site Construction

The process for site construction begins when companies are invited to bid on the site building project. Anywhere from 3 to 20 companies may be bidding on a site depending on the area that will be built upon and the exploration and production company building the site. The company who will be drilling the well gives each of the bidders a site plan with layout size and location, and the bidder is also able to go to the site to view it.

Some of the factors the bidder may need to take into consideration are how much road will need to be built to access the location, how much of a grade the location is currently on, how heavily forested the location is, and if they will need to bring in or dispose of dirt to level the location. Another consideration is how much drive time will be required to get the construction workers to and from location as labor can be the most expensive single cost in the process.

The first step in the construction process for the company awarded the bid is to call the utilities for the "One Call." This is where the utility companies such as data, gas, and water companies come out to the site and mark the utility infrastructure in place with flags so that the site construction does not damage any of the current lines in place.

The second step to the process is to determine what type of erosion control needs to be put in place. Erosion control is put into place to protect creeks, streams, and highways from damage, which can be caused if too much sediment washes off of a site while the soil is being disturbed by construction. The Department of Environmental Protection determines what type of silt protection must be put in place. The types of silt control include silt fences and silt socks. A silt fence can be either a black fabric type fence held up by wooden stakes or a chain link fence with black fabric liner. The chain link fences cost much more for both materials and installation than a fence put into place with wooden stakes. A silt sock is a plastic mesh “sock” often filled with trees that have been run through a chipper. Silt socks are often preferable to silt fences because they stay in place and are not as easily knocked over as a silt fence secured with wooden stakes. They are also much less expensive than a chain link silt fence. This step of the process can cost from $10,000 to $20.000 provided a silt fence secured with wooden stakes or a silt sock can be used.

Once the erosion control plan is in place, the roads can be constructed to mobilize the equipment needed to construct a site. Costs can vary greatly by road length and type; however average road construction for a site in Pennsylvania is from $10,000 to $20,000.

Mobilization is the process of moving the equipment to the work site and cost on average $10,000 to $20,000. During mobilization equipment such as dozers, backhoes, tractors, blades, rollers, and haul trucks are moved to the site. This construction equipment is moved to the site by a heavy haul company. This equipment will be used to level the site and create the foundation for the pad which is primarily constructed of stone.

Once the equipment is on site, the site must be stripped and grubbed. The stripping process is when any trees on the land are cut down. Any tress over six inches in diameter thick can be sold by the land owner to be used for lumber. Trees under six inches are disposed of and can be used for wood chips. Grubbing the land removes any brush and tree stumps. Stripping, also known as timber removal, is often contracted out to a third party. Depending on how heavy the tree and scrub cover is, this process can cost from $0 for a natural field to about $45,000 for a more densely treed area.

After the area has been stripped and grubbed, the location is leveled. This process begins with the topsoil being stripped and reserved. The top soil needs to be saved to be spread back out over the area during the interim reclamation so that the area is able to be seeded. The process of leveling the location is similar to leveling a location for any type of build out. The area must be dug out or filled in to create a level lot. This process is done one foot at a time with each foot of soiled being compacted using a smooth drum to ensure each layer is the proper density to prevent mudslides in the case of a heavy rain. The location also has a 40 inch berm to contain any type of water or fluid spill. The berm protects the surrounding area from contamination should any fluids be spilled. Leveling a location in Pennsylvania costs on average $125,000 to $300,000, as the landscape is primarily marked by hills making leveling necessary.

At this point, a frack pond would be built if one was needed. The average cost for a frack pond is $60,000 to $80,000.

After the earth work for a location has been completed, the pad is then constructed of rock. The base of the pad is 8 to 12 inches thick and constructed of a coarse aggregate. On top of this layer is 3 to 4 inches of aggregate referred to as crush and run which is a finer aggregate material with smaller particles in it. When the crush and run is rolled using a smooth barrelled roller, it appears similar to a parking lot. On average a site requires $10,000 to $20,000 worth of rock. The average price of rock is $25 to $30 a ton, with some variation for proximity to a quarry.

Once the pad is constructed, the final stage in building the site is to seed the slopes on the outer edges of the site, as well as the berm. Seeding and netting (or matting) is done to help reestablish vegetation to prevent soil erosion. Proper erosion control is in place when 75% vegetation is achieved. If the areas are relatively flat and accessible, then the area can be seeded and the seed covered with straw to keep it in place and provide moisture control. When an area is less accessible, matting maybe used to seed and protect the area. This process can cost from $20,000 to $50,000 per site. This is an important process in protecting the areas around the site from erosion damage.

When the site construction is complete the equipment is mobilized off of the site and the next steps of the process can begin. Table 7 summarizes the costs associated with site construction.

Table 7 – Costs associated with site construction

Step	**Low**	**Average**	**High**
One call	-	-	-
Erosion control	10,000	15,000	20,000
Roads	10,000	15,000	20,000
Mobilization	10,000	15,000	20,000
Strip and Grub	-	23,000	45,000
Level Location	125,000	213,000	300,000
Pond and Liner *	60,000	70,000	80,000
Rock	10,000	15,000	20,000
Seeding and Matting	20,000	35,000	50,000
Total	245,000	400,000	555,000

* Based on a $40,000 liner

5.4 Drilling

A Marcellus Shale natural gas well drilling operation can be broken down into two distinct phases. During the first phase of the process a vertical well bore is drilled down to a point just above the Marcellus Shale, and casing is placed into the wellbore. The casing not only protects the integrity of the wellbore from collapse, but more importantly it protects any water aquifers through which the well bore passes. The second phase of drilling a Marcellus Shale well utilizes some of the newest technologies available to the industry. Drilling contractors will use down hole motors and electromagnetic survey equipment to steer the drill bit in any direction while drilling a wellbore reaching thousands of feet through a seem of Marcellus Shale that sometimes is less than 20 feet thick. The horizontal portion of the well allows for the well bore to have much more surface area;

resulting in much greater amounts of gas that can be extracted. The benefit of this drilling technique is that a single horizontal well can produce the same amount of gas as six to ten vertical wells. Although there are various components of each section that are found in both the horizontal and the vertical stages, the costs of these are distinct to each stage of the drilling process.

The total cost of drilling is contingent upon the final depth and length of the well bore. The Marcellus Shale formation lies approximately 7,000 feet below surface in the Southwestern Pennsylvania area of the Appalachian Basin. Once the vertical portion of the well bore is drilled to a depth just above the Marcellus Shale (approximately 6,000 feet) the section of the well bore referred to as the “curve” begins. This curve section will generally take 1000 vertical feet to drill. The depth, at which the curve lands and becomes horizontal, or parallel with the surface, is commonly referred to as the Total Vertical Depth, or “TVD”. The horizontal portion of the well will be drilled approximately 4,000 feet straight out from the bottom of the curve and running within the Marcellus Shale the entire way. The result is a well bore approximately 11,000 feet in Total Measured Depth, or as it is commonly known in the industry, TMD.

Due to the high cost involved, most production companies do not own and operate their own drilling rigs. Instead, a production company will contract this work out to companies that specialize in the drilling process.

It is common for two different drilling rigs to be utilized during the drilling of a single Marcellus Shale well. A smaller rig that drills in a manner referred to as “air drilling” first drills the vertical part of the well bore leading directly down to just above the Marcellus formation. Air drilling rigs pump high volumes of air down through the drill bit and use the air to carry the cuttings back to surface. A second and most times much larger rig is then moved in to drill the horizontal phase of the well bore. This larger rig uses water based or oil based drilling fluid, commonly referred to as “drilling mud” to circulate the cuttings back to surface during the drilling operation. It is necessary to use a fluid drilling rig for horizontal phase of the well bore due to the fragile nature of the Marcellus Shale. The fluid is non-compressible; therefore it holds the wellbore open for around the drill pipe throughout drilling operations until casing can be ran in the wellbore. The heavy weight (usually between 12-14 lbs per gallon) of the drilling fluid also helps hold down any unexpected gas pressure that may be drilled into (generally referred to as a “kick”).

For a typical well site the total cost of the horizontal drilling rig rental, along with the cost of labor, averages $225,500 for a well that takes between 25 to 30 days to drill. Overseeing the operation and logistics of the drilling operation is a Drill Site Manager, whose fee averages $25,500. In addition to these costs the production company must pay for the mobilization and assembly of the drilling rigs, with an average cost of $32,250.

During each drilling phase, the drilling rig is contained within a special containment area encased in pit liners. These liners can cost approximately $24,000 per site and are only in place to prevent contamination to the soil if there are any unplanned releases of fluids from either the horizontal and vertical drilling rigs.

Additional costs of such things as float equipment, centralizers, and baskets will cost the production company $11,750. These items will be used in the process of lining the wellbore with protective casing. After the rig is positioned on the pad, additional costs that are covered by the production company include the fuel used to operate the rig and the cost of the various drill bits and reamers used throughout all phases of the drilling operations. The cost of fuel to operate the rig totals on average $32,250, with the cost of the drill bits and reamers totaling $50,000. Further costs include the rental of the instruments and tools that control the direction of the drill bit, which total $45,000. There are also costs for various trucking needs, which total $5,000 and the rental of miscellaneous tools and services for $56,500.

Diesel generators provide all of the power to the drilling sites. These generators are normally provided as part of the leased equipment set with the drilling rig. As many as three 700amp diesel A/C generators power each site. The generators use a variable frequency drive and produce about the same level of power as the power grid provides to a house. Two are typically active at all times, while the third generator is on standby; generators rotate use cycles to prevent overuse and breakdowns.

The fuel used is off-road diesel, a red-dyed tax exempt form of a diesel. It is less expensive than standard diesel, but is of a lower quality. The total diesel expense for a drilling site is approximately $200,000. The diesel expense covers not only the generators, but also other diesel vehicles. The generators consume approximately 2000-3000 gallons of diesel per day. Fuel costs for generators come to between $50,000 and $75,000 per site. This is based on 2000-3000 gallons per day x 25 days (standard drilling period).

Total costs for the drilling of the vertical section of the Marcellus well before drilling even begins, averages $457,500.

During the drilling of the well, steel tubing, known as casing, is cemented into the ground. During the vertical phase, there are four different sizes of casing that are used. The first section is referred to as the conductor pipe and is generally 20" in diameter and 20 to 40 feet long depending on the depth of the first encountered solid rock in the well bore. The purpose of the conductor pipe is to provide a strong base for construction of the well bore and the subsequent casing pipe. There is no cement used in the installation of the conductor pipe as it is generally driven into solid rock. The second section of casing is also known as the surface casing and has a diameter of 16 ¾ ". This casing is used to a depth that surpasses the level of the water table. The cost of the surface casing on an average Marcellus well is $19,500. The cement that the casing is surrounded with will cost an additional $15,000. Next the 1st intermediate casing, known as the coal string casing because this casing is used to take the well to a depth past the natural layer of coal that is in the ground, is inserted into the well. The 1st intermediate casing is 11 ¾" in diameter and is inserted to a depth of approximately 650 ft and is continued upward until it reaches the surface. The cost of the coal string casing is $12,625, with the cement for this stage adding an additional $10,000. Finally, the 2nd intermediate casing is inserted to a depth of 2,650 ft and once again continued upward until, it reaches the surface. The depth to which the 2nd intermediate casing is inserted is much greater than the surface casing and the 1st intermediate casing due to the fact that this is the casing which will reach a point below all possible water aquifers and mines. The cost for this casing runs much higher due to the length of the casing string, $51,500, with the cost of the cement totaling $20,000. After all of the casing has been inserted, a wellhead is placed on well to hold each layer of casing in place. The cost of the wellhead equipment is $5,000.

Throughout the entire vertical drilling operation the total amount of water used is very minimal in respect to other operations later in the completion process of the well. The only water needed during the vertical drilling phase is used keep the dust suppressed coming from the well bore and into the lined cuttings pit during air drilling and also for cementing each casing string. The amount of drilling water needed varies from well to well, but is typically about 500,000 gallons per well. This results in costs for the fresh water for drilling of 500,000 * $ 3 per thousand gallons[13] = $ 1,500, based on a price for the water ranging from $ 3 to $ 15 per thousand gallons, but normally at the lower end. The gas companies pay on a 1,000 gallon basis[14]. Gas companies also have water sharing agreements with other operators to reduce the industry impact[15].

Depending on the geological characteristics of the location, the water used for drilling may be stored in a pit or in frack tanks[16]. The amount of tanks varies, but is around six on average. The storage tanks are leased. The costs associated with this lease depend on the company and the size of the tank[17].

Usually, the water used for drilling activities is brought to the location by trucks. The amount of pipeline needed depends on the location of the water source in comparison to the well site. The longest distance they have piped water to a location is approximately five miles (Drilling specialist, personal correspondence). The pipelines are rented and charged per foot of pipe rented. As the cost associated with the lease of pipelines is $ 90

[13] The lowest costs for water are assumed, since the lower end is the normal case.

[14] Source: EQT

[15] Source: EQT

[16] Source: EQT

[17] Source: EQT

per foot, the maximum costs for the pipeline needed in that context is 5 * 5280 feet * $90 = $2,376,000. For the purpose of pumping, a temporary line is used to pump in the water source. As is all the drilling equipment, it is rented.[18]

The costs for the other ingredients of the drilling water, meaning the mud, are approximately $ 7,500 to $ 25,000 per well. The amount depends on how much horizontal drilling is necessary[19]. Normally, the drilling mud can be reused for a certain period of time before it begins to break down and needs to be disposed of properly.

Total costs for the drilling of the vertical portion of an average Marcellus Shale in Southwestern Pennsylvania will cost a production company $663,275.

After the drilling of the vertical well has been completed, and the casings have been cemented into place, the vertical well rig is removed from the site.

As with the vertical drilling rig, most production companies do not own their own horizontal drilling rigs and must turn to drilling companies for this stage of the process. The cost of the horizontal drilling rig rental, and the labor required to operate the rig averages $209,000. Mobilization and set up of the horizontal drilling rig costs $171,000. Once again it is required that a Drill Site Manager be hired to oversee the operation of the horizontal rig, at a cost of $26,500.

Rentals of additional items such as float equipment, centralizers, and baskets will cost the extraction company $15,000. Further costs that are covered by the production company include the fuel used to operate the rig and the cost of the various drill bits and reamers used during the horizontal run. The cost of fuel totals on average $38,000 with the cost of the drill bits and reamers totaling $4,000. There are also costs for various trucking needs, which total $25,000 and the rental of miscellaneous tools and services for $144,750.

[18] Source: EQT

[19] Source: EQT

On average the costs incurred by the production company for the set up and operation of the horizontal drilling rig is $633,250.

Horizontal drilling commences at the kick off point at the bottom of the vertical well. A typical horizontal lateral may be approximately 5,000 feet in length, although in drilling there are variables, such as geology, that effect the drilling decisions. These factors may allow drilling to take the laterals longer, up to as long as 9,000 feet, with a typical decision rule of going “as far as we can laterally while still being economical” (Production specialist, personal correspondence, August 18, 2011).

New technology has enabled drilling rigs to control the drill bit so that they can turn the well from a vertical well into a horizontal well. In order to do this, the extraction company must also rent equipment that is specially designed to control the drill bit as it makes the turn from a vertical direction to a horizontal direction. The cost of this equipment is $85,250. After the drilling is complete, 5 ½” casing, known as production casing, is inserted into the well at a cost of $248,500 and secured with $80,000 in cement. Additional costs include $4,000 for the hauling of water used during the cementing process. The wellhead equipment for this stage of the drilling has a total cost of $25,000.

For drilling, it requires some special equipment to separate the drill cuttings from the water. These shakers are included in the rig cost. Disposal of drill cuttings requires about eighty truckloads, which cost about $250 each. One truckload contains 62,000 pound or about 28 metric tons of material (Drilling supervisor, personal correspondence, March 25, 2011). The landfills charges vary per truckload for depositing the cuttings, depending on the landfill used. These charges are impacted by special permissions that landfills need to accept drill cuttings from the Marcellus Shale.

To support both the vertical drilling process and the horizontal well drilling process, there are also costs for drilling mud and chemicals. Drilling mud; which is a combination of water, clay and various chemicals, is used to float the rock fragments, known as cuttings, and soil back to the surface. This mud is recycled and reused during the course of the drilling of the well. The well bore is filled with drilling mud just before the vertical rig moves off location to ensure the integrity of the well bore stays intact and does not collapse while waiting for the horizontal rig to arrive. Costs of filling the vertical portion the well will cost the production company $10,000 and during the horizontal drilling portion the cost is $127,800 as much more mud is needed. This mud is recycled after the well is completed and used for the next well drilling operation.

Geologists and engineers play a role at various stages of the drilling. They are not only involved during site selection, but also work directly on the drilling rig, collaborating with the drilling crews, to analyze and fine tune the progress of the drilling. So, in addition to the costs associated with the drilling mud, there are fees paid by the production company to geologists who are employed to complete analysis of the drilling mud and cuttings that are brought to the surface. This process is known as mud logging, and enables the crew of the rig to know what geological elements the well is encountering below the surface. This knowledge is important not only to the drilling, but to tuning the chemical composition of the drilling mud to best suit conditions at the drilling depth. The cost of this service is $12,000 during the vertical portion and for the horizontal portion of the well the cost is $11,050.

Total costs for the drilling of the horizontal portion of a Marcellus Shale well in Southwestern Pennsylvania will cost a production company on average $1,214,850.

At this point the drilling is complete and the production casing is in place. The horizontal drilling rig is now ready to be deconstructed and moved to another drilling site. These costs are included in the original mobilization costs referenced above.

Final costs for the drilling an 11,000 foot Marcellus well costs on average $1,878,125. A breakdown of drilling costs is shown in Table 8. In summary, depending on conditions experienced, it takes approximately 18 – 21 days to drill a Marcellus well.

Table 8 - Costs Associated with Drilling

VERTICAL DRILLING	
Surface Casing (fresh water): 16-3/4”	$19,500
1st Intermediate (coal string): 11-3/4”	$12,625
2nd Intermediate Casing: 8-5/8”	$51,500
Wellhead Equipment	$5,000
Float Equipment, Centralizers, Baskets, etc.	$11,750
Daywork Drilling	$225,000
Rig(s) Mobilization: All Rigs	$32,250
Fuel	$32,250
Bits, Reamers, Tools, Power Tongs	$50,000
Pit Liners	$24,000
Drilling Mud & Chemicals	$10,000
Drilling Miscellaneous (directional drlg, gyro)	$45,000
Cement Surface Casing	$15,000
Cement 1st Intermediate Casing	$10,000
Cement 2nd Intermediate Casing	$20,000
Trucking	$500
Mud Logging	$11,900
Engineering Consultant / Well-site Leader	$25,500
Miscellaneous Tools, Services & Rentals	$56,500
Haul Fresh Water for Cementing / Rig	$5,000
Vertical Drilling Subtotal	**$663,275**
HORIZONTAL DRILLING	
Production Casing: 5-1/2”	$248,500
Wellhead Equipment	$25,000
Float Equipment, Centralizers, Baskets, etc.	$15,000
Daywork Drilling: Spudder, Intermediate & Horizontal Rigs	$209,000
Rig(s) Mobilization: All Rigs	$171,000
Fuel	$38,000
Bits, Reamers, Tools, Power Tongs	$4,000
Drilling Mud & Chemicals	$127,800
Drilling Miscellaneous (directional drlg, gyro)	$85,250
Cement Production Casing	$80,000
Trucking	$25,000
Mud Logging	$11,050
Engineering Consultant / Well-site Leader	$26,500
Miscellaneous Tools, Services & Rentals	$144,750
Haul Fresh Water for Cementing / Rig	$4,000
Horizontal Drilling Subtotal	**$1,214,850**
TOTAL DRILLING COSTS	**$1,878,125**

Various other factors may impact the cost of drilling and fracking, such as the cost of any necessary security measures, if needed. Given the nature of the expensive drilling components, sites may choose to store and secure certain equipment or materials such as drilling bits and expensive parts in secure storage containers, such as CONEX steel storage containers. Each of these containers costs between two to four thousand dollars, and up, depending on size, plus the costs of transportation to the well site. Purchasing security fencing for a well site may cost between $60,000 and $110,000, although fencing rental may cost less.

5.5 Hydraulic Fracturing

Once the Marcellus Shale well has been drilled and the casing has been inserted and cemented for at least 24 hours to cure, it is time to begin the Completions Phase. Completions account for 40% - 60% of the overall cost to complete a well. An estimated industry average, per foot, for completions is $500 - $600. This amount varies primarily on the length of the lateral and number of engineered stages. If the lateral length is long, there is more length to divide the fixed costs among, thus lowering the price per foot. If the number of stages to be completed is high, there will be additional time and material required to complete the fracturing, thus raising the price per foot. For a 4,500' lateral Marcellus Shale well, an estimated all inclusive cost can be estimated at $2.5 million, assuming 15 fracturing stages. Hydraulic fracturing companies that provide service to Marcellus Shale play include Halliburton, BJ Services, Baker Hughes, Calfrac Well Services Ltd., and Schlumberger.

The first step in the Completions Phase is to clean out the well. A perforating gun must then be inserted into the well and taken to the very end of the lateral section. These two steps can be done by using a coil tubing rig. On occasion, the perforating gun may be inserted by the directional drilling services, depending on the situation. The cost to initially clean out the well and perforate the first stage can be estimated at $35,000 -

$50,000. This process, if completed via coil tubing, will require a 3 - 5 man crew and a coil tubing rig.

Once the first stage has been perforated, the gun is removed and the Fracturing Phase begins. Water is pumped down hole at a rate of 75-100 bpm. This is accomplished with the assistance of 12-18 large water pumps on tractor trailers, circled around the wellhead. All water pumps are connected with highly pressure rated water lines. The water pumps' combined hydraulic horse power is 25,000 - 30,000. The water is pulled from on-site water completion pits that are capable of holding millions of gallons of water. There are also other means of providing water for fracturing. As water is pumped down hole, casing pressure begins to rise. The pressure required to fracture the Marcellus Shale is between 6,500 and 9,000 psi depending on the formation present. The average is 7,000 psi to stimulate the shale. The water is mixed with additives to create a "fracking fluid", which is pumped down hole, and into the perforations in the casing, made by the perforating gun. The "fracking fluid" squeezes out from perforations in the 4,000- to 8,000-foot-long horizontal arm of the well, which extends through the sedimentary formation, and causes the shale to crack. The shale is tightly compressed and does not release the sought after quantities of gas until fractured.

Estimated consumption of diesel fuel to complete a single stage by the 12 - 18 water pumps is 4,000 gallons. Current diesel fuel prices for off road quality is $4 per gallon.

Generally, the amount of fracking water needed varies from well to well. For that reason, different information can be found in this context. Between 4 to 4.5 million gallons and 5.6 million gallons of fresh water per horizontal well are needed for fracking (Drilling specialist, personal correspondence; Chesapeake, 2010). Other sources estimate the amount of fresh water necessary for fracking a horizontal well at approximately 3 million gallons (Soeder and Kappel, 2009; Airhart, 2007). On the contrary, a recent study of Penn State University estimates the fresh water usage for a horizontal well between 4 and 8 million gallons (Abdalla and Drohan, 2010). An article in the Pittsburgh Post-Gazette indicates that 4 million gallons of water, sand and chemicals are needed for each well (Hamill, 2011). For a vertical Marcellus Shale well, a water consumption of

500,000 to more than 1,000,000 gallons of water is assumed (Harper, 2008). Since most of the Marcellus wells are horizontal, for the estimation of the economic impact of a Marcellus well, an assumption of 4 million gallons fresh water usage for the fracking process seems to be reasonable. This would result in costs for the fresh water of 4 million gallons * $ 3 per thousand gallons[20] = $ 12,000. Some Marcellus well may need to be hydrofracked several times throughout their productive life (Abdalla and Drohan, 2010).

The fracking water is usually stored in one or two pits. The cost for a pit varies depending upon the size of the completion pits, the amount of the overburden that needs to be removed, the terrain, the topography and other factors. On average the cost for building a pit are around $120,000 and another $60,000 to $70,000 for lining and fencing. There are no real maintenance efforts necessary for the pits other than routine inspections and occasional, minor repairs to the liner[21].

As for the drilling water, a pipeline is also needed for the transportation of the fracking water. In that context, depending on the distance from the water source to the completions pits that are used to store the water, a few thousand feet to several miles (up to 5 miles) of pipeline are necessary. The pipelines are rented and charged per foot of pipe rented. As the cost associated with the lease of pipelines is $ 90 per foot, the maximum costs for the pipeline needed in that context is 5 * 5280 feet * $90 = $2,376,000[22].

Occasionally, storage tanks are used for the storage of the water in addition to the pits.
The pumps for the frack water are typically rented from water transfer companies. The costs vary depending on the length of the run, how many days the pumps are utilized and other factors.

[20] The lowest costs for water are assumed, since the lower end is the normal case.

[21] Source: EQT

[22] Source: EQT

Apart, from fresh water, the frack fluid includes other ingredients. The costs for those are part of the completion costs that are typically performed by service companies such as Halliburton and BJ Services.

Sand is used during the process to help propagate the fractures and allow gas to flow more easily. Estimated usage of sand is 250 tons per 300 foot stage. The current price of sand, including delivery, is estimated at $4 per ton. This is dependent upon diesel prices and site location. There are various grades of sand that can be used.

Although not widely understood by many, the typical makeup of fracking fluid is available from a number of publicly available sources.[23] Fracking fluid is comprised of 92.23% water, 6.24% sand, and the remaining 1.54% makes up the fluid system or additives that aid the efficiency of the fracking fluid (Halliburton, 2011). The specific compounds used in any given fracturing operation vary depending on company preference, source water characteristics, and site-specific characteristics, such as the salinity of the deposits. Common components of these include hydrochloric acid (HCl), friction reducers, biocide agents, and scale inhibitors (Halliburton, 2011). The total costs for the additional ingredients is between $ 75,000 and $ 200,000[24].

A small amount (about 10-20%) of the fracking water flows-back, typically within the first two weeks after the process, and needs to be disposed of. It is this fracking water that is of environmental concern, as it may contain both fracking solution, as well as brine and other minerals from the well itself. About 10% of the fracking water flows back during the operation of the well. This water can partly be reused for fracking.

In the context of 220 wells in the Susquehanna River Basin, during the period from June 1, 2008, to May 21, 2010, 59% of wells used flowback water in fracking, and 88% of the flowback water brought onsite is used (Abdalla and Drohan, 2010). In these 220 wells,

[23] For example, information on the composition of fracking fluids are available from the government (U. S. Department of Energy, 2009; Litvak, 2010; http://assets.bizjournals.com/cms_media/pittsburgh/datacenter/DEP_Frac_Chemical_List_6-30-10.pdf) and from industry suppliers (Halliburton, 2011).

[24] Source: EQT

the total flowback reused was 44.1 million gallons, while flowback disposed constituted 21.0 million gallons (Abdalla and Drohan, 2010).

Besides that, the process for both kinds of water (water from the drilling process and fracking water flows-back) is identical. Nevertheless, taking care of the water is a continuous process throughout the entire lifetime of the well, even though the flow-back will only be between 5-100 barrels per day. As fracking requires 4.5 million gallons of water on average, 450,000-900,000 barrels of water need to be recycled during this period.

The cost for the recycling of both types of water highly depends on the degree of purification desired for the flow back water. The simple disposal of the water costs between $10-$14 per barrel, although recent regulatory changes have limited water treatment plant's acceptance of Marcellus Shale waste water. The costs for recycling water range between $3.50 and $5.50 depending on the level of purification achieved. The lower costs refer to water that still contains salt and some minor chemicals and can be reused for the process. The $5.50 version is extremely purified and can be classified as potable.

Several options of achieving recycling or disposal are available. Either a mobile unit that can be placed on site to limit transportation costs, trucking the water to a wastewater treatment plant, trucking the water to an underground injection site, or building a pipeline system to the plant. The latter option would have the lowest variable costs, but only makes sense if multiple wells exist/are planned in a condensed area. Underground injection is more expensive than recycling, but it's cheaper than treatment (Cookson, 2010).

The mobile wastewater treatment unit can either be purchased or rented. Purchasing the equipment (one unit) costs about $4 million, renting $79,500 per month. Additionally, it costs $73,000 to operate it (fuel, labor, etc.). Independent of the option chosen, the costs for water recycling are somewhat similar. The mobile clarifier incurs costs between $2-$4 per barrel, depending on the level of purification with the lower $2 cost for water that can be reused in the process (Fountain Quail Water Management, www.fountainquail.com, personal communication).

Flow back water requires between 200 and 300 tanker trucks to be shipped for recycling. A well site can choose to recycle this water back into new wells, but this accounts for all flow back being recycled to a separate well site. Recycling saves $200,000 a well and takes 1,000 water trucks off the road (Cookson, 2010).

Besides flow back water, other outputs from a wellhead could include garbage, and broken materials and equipment. Drilling companies also need to keep the rig clean and measurable, so they work with cleaning companies in the area that have the capabilities to scrub the rig properly in order to allow the engineers to read the measurements on the dials.

The hydraulic fracturing process requires an industry average 25 – 30 person crew, which includes engineering and maintenance support personnel. Once the first stage has been successfully fractured, a plug is inserted to block water from entering the completed stage and prevent gas from flowing to the surface. Along with the plug, another perforating gun is entered down hole to perforate the second stage. This can be done via coil tubing or wire line. The plug and gun are lowered to the bottom of the vertical section, but both need to travel to the end of stage one. This can be accomplished by pumping water down hole to carry the plug and gun to the desired location. Once the plug has been set, the perforating gun is discharged. The fracturing process is then repeated. Pumping plugs and perforating guns down hole requires a 3 - 5 person crew, wire line unit, crane and pressure control equipment. Plugs and perforating guns can be estimated at $5,000 - $15,000 each. Labor to perforate one stage and set a plug, on a 400’ stage, is estimated at $15,000 - $25,000.

The number of fracturing stages and the length of each stage is engineered specifically to an individual well. Estimated values on a 4,500’ lateral could be 10 - 20 stages (average 15) and 200’ - 500’ stage spacing (average 350’). A timeline to complete each stage depends on the operation schedule. For 12 hours per day operation, 2 - 3 stages can be completed. For 24 hours per day operation, 4 - 5 stages can be completed.

The all-inclusive cost per stage to fracture can be estimated at $120,000 - $180,000. This price per stage includes all previously mention costs (sand, fuel, plugs, perforating gun, services), a portion of the mobilization and demobilization costs ($75,000 - $150,000, depending on location) and fracturing services costs (remainder of costs). Additional equipment such as lighting and housing may be required for operations. These items can be rented or purchased by the producing or service companies.

For a Marcellus Shale well with a 4,500’ lateral, the average number of stages can be estimated at 15. The average length of each stage would then be 300’. Using an average of $150,000 per stage to complete ($120,000 + $180,000 / 2 = $150,000), the total cost to successfully fracture a Marcellus Shale well is $2.5 million.

5.6 Completion

Once fracturing is completed, one of the last steps is to drill out the inserted plugs, flow back and clean out the well. This process can be assumed to cost anywhere from $150,000 - $250,000. For this study, we use the average cost of $200,000, as the actual completion costs at a given well are highly dependent on the site and the amount of reclamation required. Once flow back is complete and enough water has been removed to flow to sales, the well is turned over to production operations to turn the well online.

After the drilling is completed, a piece of equipment with multiple components, consisting of casing head, tubing head, and the ‘Christmas’ tree, is installed at the wellhead in preparation for the controlled extraction of the hydrocarbons from the well. The high pressure of the gases and liquids that are being released from the well, require wellheads that can withstand pressures from 2,000 - 20,0000psi. Exposure to the weather and potentially corrosive flowback from the well necessitate non-corrosive materials and an ability to withstand temperatures ranging from -50C to 150C. The wellhead must be durable enough to prevent leaking and blowouts caused by high pressure (NaturalGas.org, 2010).

Wellhead components and costs are estimated to total between $400,000 and $500,000 (Production engineer, personal correspondence. 24 April 2011). This includes

- Installation: labor to install all wellhead components costs, approximately $50,000
- Crushed stone pad: average use of 500 tons at a cost of approximately $30 per ton. Approximate cost is $15,000
- Casing head: Heavy fittings that provide a seal between the well casing and the ground surface. Material is typically steel or steel alloy. Costs can vary from $200,000 to $300,000, dependent on the well pressure.
- Tubing head: Tubing head provides a seal between the tubing that is run inside the casing and the ground surface. Its purpose is to provide the connection to control the flow of gas and liquids from the well. Average costs range between $50,000 and $75,000.
- 'Christmas tree': The piece of equipment that fits on top of the casing and tubing heads, containing tubes and valves that control the flow of wet and dry hydrocarbons and other fluids out of the well. Its purpose is to allow for the regulation of the production of hydrocarbons from a producing well. A typical Christmas tree is about four feet tall (Sweeney, 2009) and made of steel or alloy steel. Average cost is $50,000.
- Metering system: Monitors gas production. Average cost ranges between $25,000 and $50,000.

Along with completing the wellhead, land on a well site that is not being used for production but has been disturbed undergoes interim land reclamation. After drilling activity is complete, interim land reclamation is performed based on a plan of operations approved prior to any well development activity commencing. The assessment of site reclamation requirements are based on “the site’s habitat quality, quantity of existing habitat, natural features, juxtaposition of those habitats and features on the property, plant and wildlife species currently using the property and those with the potential to use the property based on the habitat present" and can significantly vary (Department of Conservation and Natural Resources, 2011).

The approximate site area of a well during development is 300 feet x 500 feet. During interim reclamation, "40 percent of the originally constructed well pad site can be reclaimed. The remaining 60 percent of the well pad site is required for maintenance access, produced water storage, and the production equipment noted above" Therefore, the area of the interim land reclamation is approximately 120 feet x 200 feet (Anderson, Coupal, and White, 2009).

Interim reclamation components and costs are estimated to total between $500,000 to $800,000, and are highly dependent on site conditions. These include:

- Re-contouring portions of the cleared well site has an estimated cost $75,000-$150,000, but is very dependent on the topography and amounts of land moved to create the site (Construction Specialist and Production Specialist, personal correspondence, April 12, 2011).
- Reclamation of temporary roads constructed of crushed rock or stone can range between $180,000 and $250,000, dependent on the site and distance from main thoroughfares (Construction Specialist and Production Specialist, personal correspondence, April 12, 2011).
- Topsoil spread evenly (estimated 2" inches) would require approximately 6,912,000 cubic inches (or 40 tons) of soil to reclaim the site. Approximate cost of topsoil is $20 per cubic yard. Estimated total cost of topsoil would be $3,000 (CSGNetwork.com, 2011). This cost does not include the temporary roadways because distance can very so significantly. Alternatively, topsoil may be stored during the site construction phase, saving the cost of purchasing topsoil.
- Landscaping and re-vegetation using a predominately native seed mix to return the land to its natural state. If the area is farm land, it can be seeded only, which usually cost $30,000 to $50,000. If the area is heavily forested or contains other plant species, the cost of returning the land to its original status can vary widely. There may also be a land owner request where the land owner has requested a

certain tree or seed mix when reclaiming. (Construction Specialist and Production Specialist, personal correspondence, April 12, 2011).

- Retention pond reclamation, with an average cost $15,000 to $25,000 (Construction Specialist and Production Specialist, personal correspondence, April 12, 2011), includes removal of pond liner, backfill, and environmental remediation, which is only required if the pond liner is breached.
- Public road repair is highly dependent on the amount of damage done from well development activities. Some municipalities are planning to request that site operators set aside $150,000 to $300,000 for public road repairs (Bath, 2011) Prototypical road use agreements in Pennsylvania require that on “the completion of the User’s operations, the User, at its own cost and expense, shall within 60 days restore the roadways to the same or better condition as existed prior to the commencement of User’s operations.” (Center for Dirt and Gravel Road Studies, 2011). Costs for roadwork can exceed $500,000 or higher, depending on the site (Construction Specialist, personal correspondence, April 12, 2011).
- Fencing (160 feet x 300 feet) is typically installed as chain link fence. With each section 6 feet high and 6 feet wide, it rents for approximately $215 per month, or $1.42 per 6 foot wide panel. Total rental cost will vary depending on the amount of time the well is producing and the fencing is needed (National Construction Rentals Representative, personal communication, April 26, 2011).

5.7 Production

5.7.1 Gathering pipelines

After the drilling and fracturing are done, natural gas begins to flow from the well and pipelines are installed to transport the gas from the wellhead to the market. According to American Petroleum Institute (API), the natural gas pipeline network involves three systems:

- *Gathering systems*: Production wells are connected through small-diameter pipelines that move pipeline-quality gas from the wellhead directly to the mainline transmission grid. However, since much of the natural gas produced from the

Marcellus Shale wells in Southwestern Pennsylvania is “wet gas”, it needs to be further refined in a processing plant to remove impurities and natural gas liquids (NGLs) such as propane and butane (Considine, 2010), before entering the transmission systems.

- *Transmission systems* “carry the processed natural gas, often over long distances, from the producing region to local distribution systems around the country” (American Petroleum Institute, 2011). The transmission systems consist of 29 percent of intrastate pipelines and 71 percent of interstate pipelines.
- *Local distribution systems*: A distribution system, such as local utility, connects to the interstate pipeline at a “city gate” (American Petroleum Institute, 2011b). The natural gas is then delivered to homes, businesses and other end customers.

Based on our research scope of a single Marcellus Shale well, we will only include the gathering systems in our evaluation of the value chain. The economic impact of the gathering systems starts with pipeline companies acquiring right-of-way through the negotiation of an easement with the landowners along the pipeline route. Rights-of-ways and easements provide “a permanent, limited interest in the land that enables the pipeline company to operate, test, inspect, repair, maintain, replace, and protect one or more pipelines on property owned by others” (USDOT). Both the company interview and other sources (Messersmith, 2010) suggest that the right-of-way easements in Pennsylvania have ranged between $5 and $30 per linear foot. Easements are affected by factors such as size of pipelines, numbers of pipelines, and the width of right-of-way. Landowners’ attitude also plays a key role in determining how much will be paid. If there is no route around the parcel of land, the production or pipeline company will may pay the asked amount. However, if there is an alternate route to connect point A with point B, then the alternate is taken to reduce the costs in lieu of inflated easement payments.. Since there are multiple factors in determining the easements, companies negotiate the payment on a case by case basis. In our assessment of the value chain, we will assume $15 per linear foot is the average payment, in order to demonstrate how different payments of easement would impact the value chain.

After securing the rights-of-way, gathering lines are built before production activities begin. According to Marcellus Shale Coalition, some of its member companies are "exclusively gathering pipeline companies," but "many exploration and production companies also currently have, or may plan to build gathering lines in the future." (Wurfel, 2010). Gathering pipelines connect multiple wells, and depending on the production volume, the size of the pipelines range between 4 to 24 inches in diameter (Klaber, 2010b). Our company interview reveals that the installation and material cost of gathering pipelines is approximately $90 per foot. Therefore, the total cost of gathering pipeline construction is between $95 and $120 per linear foot, with the right-of-way easement being the major contributing factor to the difference.

Table 9 - Costs Associated with Gathering

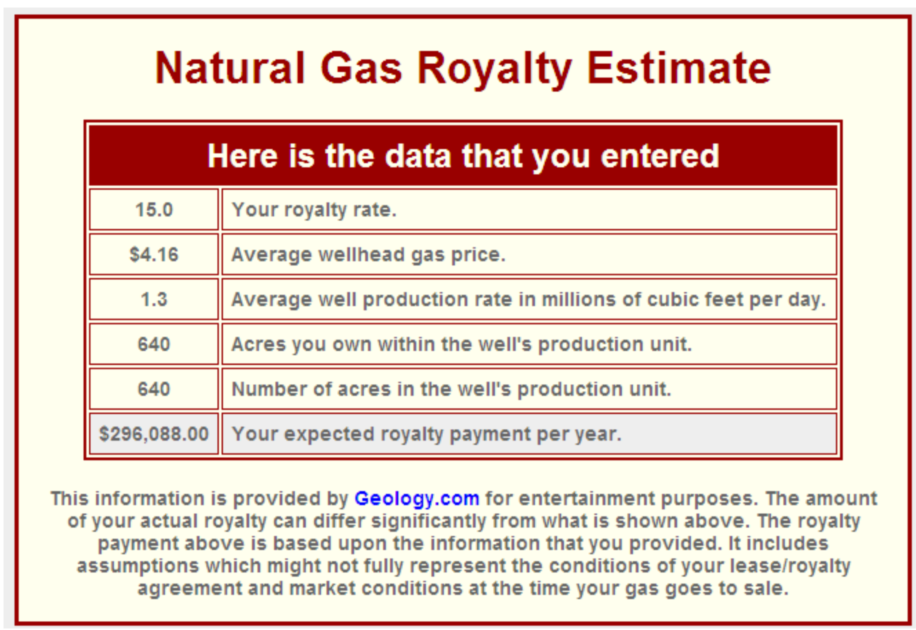
Gathering Pipelines	**Best Case**	**Likely Case**	**Worst Case**
Right-of-Way Easement	$5	$15	$30
Material & Installation	$90	$90	$90
Cost (per foot)	$95	$105	$120
Average Length of Gathering Pipelines for Single Well (ft)	4,500	4500	4500
Total Cost (per well)	$427,500	$472,500	$540,000

However, since "the typical Marcellus gathering line has a diameter and a pressure higher than other legacy production and gathering systems within Pennsylvania", some industry data also indicates the economic impact in each mile of new pipeline is approximately $1 million (Klaber, 2010a), which is equivalent to $189 per linear foot.

5.7.2 Royalty

The mineral lease agreement between the landowners and the producer is negotiated prior to drilling a gas well. The lease payment, however, "holds the lease on the oil and gas property until drilling and production occur, and thereafter, the lease is held by production until production stops." (DEP, 2010). The minimum royalty on production to the landowners is prescribed by law and set at 1/8, or 12.5%, of the value of the produced oil or gas (Oil and Gas Leases, *58 P.S. § 33 and § 34*). Based on our company interview, royalty ranges from 12.5% to 25%, and the current industry average is approximately 15% (Green, February 28, 2010).

There are multiple royalty calculators available in estimating the total royalty payment to the landowners (Penn State, 2011). Among them, Natural Gas Royalty Estimate (Geology.com, 2011) is widely adopted by the production companies in communicating to the landowners about the projected royalty payment. An example is shown in Figure 4.



Natural Gas Royalty Estimate

Here is the data that you entered	
15.0	Your royalty rate.
$4.16	Average wellhead gas price.
1.3	Average well production rate in millions of cubic feet per day.
640	Acres you own within the well's production unit.
640	Number of acres in the well's production unit.
$296,088.00	Your expected royalty payment per year.

This information is provided by Geology.com for entertainment purposes. The amount of your actual royalty can differ significantly from what is shown above. The royalty payment above is based upon the information that you provided. It includes assumptions which might not fully represent the conditions of your lease/royalty agreement and market conditions at the time your gas goes to sale.

Source: geology.com/royalty/

Figure 4 - Example of a Natural Gas Royalty Calculator

The above estimate is based on one production unit, which is also the minimum optimal size in drilling a natural gas well. In order to calculate the royalty payment for one production unit, the following assumptions were made: average industry royalty rate of 15% for Marcellus Shale well, wellhead gas price of $4.16 based on the average of year 2010 (U.S. Energy Information Administration, 2011), average well production rate of 1.3 million cubic feet per day (Harper and Kostelnik), and only one well existing in one production unit of 640 acres. The estimate shows that expected royalty payment to the landowners is approximately $300,000 per year. The differences of royalty rate, however, could significantly affect the yearly payment of royalty over the lifetime of well production.

Table 10 – Natural Gas Royalty Estimates

Natural Gas Royalty Estimate	**Best Case**	**Likely Case**	**Worst Case**
Royalty rate	12.5%	15%	25%
Average wellhead gas price	$4.16	$4.16	$4.16
Average well production rate (Mcf/per day)	1.3	1.3	1.3
Acres owned within the well's production unit	640	640	640
Number of acres in the well's production unit	640	640	640
Expected royalty payment per year	$246,740	$296,088	$493,480

Source: Adapted from geology.com/royalty/

Another factor that will possibly affect the royalty payment is average well production rate. Since the drilling activities in Marcellus Shale play only started a few years ago, the average decline rate of the production in the natural gas wells has yet been determined. When more research reports regarding the average production rate of a single well available in the future, the estimate of royalty payments should be revised accordingly.

6 Issues and Opportunities for Pennsylvania

A number of issues and opportunities are presented by the current state of the Marcellus Shale play in Pennsylvania. These include:

- Developing a Marcellus ecosystem
- Changes in the economic model, such as drilling taxes or fees
- Workforce development
- Understanding the indirect and induced economic impacts

The following paragraphs introduce each of these issues and opportunities for addressing the challenges of Marcellus Shale drilling in Pennsylvania.

6.1 Developing a Marcellus Ecosystem

Since most production companies are existing oil and gas drilling companies in the industry, they have abundant experience and resources in managing the supply chain of drilling a well. Although some companies are vertically integrated, others use vendors for most of the drilling-related activities and thus create various outsourcing (or contracting out) opportunities in the supply chain.

Throughout this study, we saw multiple evidences of large firms, such as Halliburton, as well as many small entrepreneurial firms providing services in the Marcellus Shale industry. A main challenge for local companies (or governments) in the industry is to figure out how to retain these activities as much as possible in Pennsylvania, and maximize the revenue coming from the value chain of drilling the Marcellus Shale wells.

Through the advocacy of small-enterprise involvement in the Marcellus supply chain, the region stands to benefit enormously. Small business owners are faced with opportunities to enter a new market, while expanding their labor force and expediting growth. To that end, regional development can be spurred on in the form of increased hiring, investment, and experience/knowledge-building. The necessary steps should be taken to ensure that the small-business economy within the region is prepared to capitalize on this opportunity. Entrepreneurship is a fundamental component to any emerging industry, and the natural gas industry is no different. Proper development and support of entrepreneurs and their ventures can help lead to significant economic development in Marcellus Shale-related opportunities throughout the region.

6.2 Changes in the Economic Model

Drilling Taxes or Fees, such as severance taxes, could change the economic model for Marcellus Shale exploration and production. Proposals in Pennsylvania last year would place a tax of 39 cents per thousand cubic feet (or Mcf) (Head, 2010). There are multiple proposals that have been floated in 2011. These proposals would place a severance tax equal to 5 percent of the value of natural gas extracted plus 4.6 cents per thousand cubic feet (mcf) (Kasey, 2011) or a 2% tax on the gross value of natural gas at the wellhead where the amount produced is between 60,000 to 150,000 cubic feet/day (cf/d) and, for wells that have been in production longer than three years, the tax rate would increase to 5% (Bagnell and Nieland, 2011).

Some experts predict increased environmental or compliance costs associated with shale gas production, with increases estimated to range from $200,000 to $500,000 per well or greater (Natural Gas Weekly, 2010). Industry analysts predict additional costs beyond these of $125,000 to $250,000 per well if the U.S. Congress mandates EPA oversight of fracking (Natural Gas Weekly, 2010; Pursell & Vaughn, 2010).

These increased taxation, environmental, or compliance costs will change the economic model developed in this study, as each would potentially change the direct economic impact of exploring and producing natural gas from a Marcellus Shale well.

6.3 Workforce Development

The Marcellus Shale play has been predicted to result in increased employment, with projections of up to 110,000 jobs in Pennsylvania (Toland, 2010). Firms in the industry have grown by adding or planning to add employees (Green, November 10, 2010; Mellott, 2010; Woodall, 2010). Range Resources planned to more than double its employee size from 300 to 700 and Chesapeake also expected growth (Woodall, 2010), while Atlas grew in employee size from 500 to 700 at the beginning of 2010 (Green, November 10, 2010).

While projections are high, and some uptick in employment is reported, certain economists have argued that encouraging oil and gas production is not an effective strategy for creating jobs. (Remarks of Alan B. Krueger, Chief Economist and Assistant Secretary for Economic Policy at the US Department of Treasury, to the American Tax Policy Institute Conference, October 15, 2009, cited in Barth, 2010). Hamill (2011) reports that each well generates the equivalent of 11-13 full-time workers employed for a year, spread over hundreds of participants across the work force.

But, the job growth occurring is not always directly benefitting the Pennsylvania workforce, as sufficient numbers of Pennsylvania workers to meet the demand “aren't trained to do the actual drilling jobs…so many roughneck and rig crews rotate in and out of Pennsylvania but are based elsewhere.” (Toland, 2010). In some drilling areas, local observers have reported “many license plates from Texas, Oklahoma and Louisiana are now seen on local roadways.” (Junkins, 2010). One analyst has claimed that “70% of gas employees are from out of state. While an increasing number of wells were drilled in 2008, and statewide employment in the oil and gas extraction industry dropped in 2008 (Barth 2011).

The US Government maintains the H-1B Specialty Occupation Visa Program, which provides non-immigrant, temporary visas to the United States to perform services in specialty occupations (USCIS, 2011). Each petition for an H-1B worker must be accompanied by a Labor Condition Application certified by the Department of Labor. The Department of Labor Foreign Labor Certification data indicates an interest by U.S. employers to hire foreign workers.[25] A review of the Foreign Labor Certification Data Center[26] data for the most current year available (Fiscal Year 2010) H-1B Labor Condition Applications (LCAs) shows that Marcellus firms, such as Halliburton, EQT Gathering, and Consol Energy, are filing applications to denote their interest in hiring foreign H1B visa holders for work in the US. These three firms alone accounted for 78 of

[25] FLC Disclosure Data; http://www.flcdatacenter.com/CaseData.aspx

[26] The Foreign Labor Certification Data Center is developed and maintained by the State of Utah under contract with the US Department of Labor, Office of Foreign Labor Certification.

the 335,328 LCAs filed during Fiscal Year 2010. Wage rates for these jobs ranged from $53,000 for a staff auditor to a high of $300,000 for a Vice President postion. A sampling of these 78 job titles is shown in Table 11. They span positions from accounting and budgeting to software development to consulting to supply chain and sourcing and a wide variety of engineering and production positions.

These same three firms accounted for thirty-six H1B visa applications granted in Fiscal Year 2009 (USCIS, 2009). Training Pennsylvanians for natural gas jobs is a component of the recommendations in the recent Governor's Marcellus Shale Advisory Committee report (2011), although it may be several years before the impact of this training is seen in the workforce and in payroll-driven economic impacts (Nothstine, 2010). Economic impacts of implementing these recommendations could include educational services, increased employment within Pennsylvania of Pennsylvania citizens, and induced effects arising from the impact of their payroll being spent within the Commonwealth.

6.4 Indirect and Induced Economic Impacts

While this study focused on quantifying the direct economic impact of Marcellus Shale development, there exist both indirect and induced economic impacts that also result from Marcellus plays. However, the extent and quantification of these impacts are not always well understood. A recent study has shown that there is inconsistent awareness of the underlying Marcellus activities themselves (see Box 4).

Box 4: From a Penn State report on *Community Impacts of Marcellus Shale Development*

> "Overall, the study finds that rapid development in areas with low population density led to a broader awareness of natural gas impacts, both positive and negative. For instance, Washington County, one of the counties with larger population size and higher population density, was undergoing extensive natural gas development, yet many participants were unaware of specific drilling locations or activities."

Source: Brasier & Filteau, 2010

Table 11 - Sampling of Job Titles from FY 2010
Labor Condition Applications

Associate Technical Professional-Electrical/Electronics	Senior Technical Professional - Mechanical
Chief Advisor-Global Technical Services	Service Coordinator
Consultant	Software Engineer
Field Professional -Real Time Geomechanics I	Sr. Field Professional - Directional Drilling
Field Professional- Optimization	Sr. Field Professional - Real-Time Geomechanics
Gas Operations Analyst, Capital Planning & Budgeting	Sr. Field Professional-Logging While Drilling
Gas Systems Engineer	Sr. Financial Analyst
General Field Professional - Directional Drilling	Sr. IT Applications Analyst/Developer
General Field Professional-Logging While Drilling	Sr. International Sourcing Lead
Geomechanical Engineer	Sr. Logging Geologist-Surface Data Logging
Global Technical Services Advisor	Sr. Scientist-Physics
International Sourcing Lead	Sr. Technical Professional - Mechanical
Lead Accountant	Sr. Technical Professional-Eng/Petrophysical Applications
Principal Global Operations Manager	Sr. Technical Professional-Log Analysis L&P
Principal Scientist, Physics	Staff Auditor
Principal Software Engineer	Strategic Sourcing Team Lead
Principal Technical Advisor - Production - Project	Supply Chain Analyst
Principal Technical Professional-Technical Service	Technical Professional - Electrical/Electronics
Principle Technical Professional - Electrical/Electronics	Technical Professional - Electrical/Electronics Sr
Principle Technical Professional - Mechanical	Technical Professional - Log Analysis Leader
Program Manager - Systems Engineering	Technical Professional - Mechanical
Programmer Analyst Specialist	Technical Professional - Software Development
Senior Consultant - Production	Technical Professional-Electrical/Electronics
Senior IT Technical Architect	Vice President - Technology
Senior Technical Professional - Directional Drilling	

Source: Foreign Labor Certification Data Center, 2011

Some of the impacts that have been reported or projected include environmental concerns; Increased use of infrastructure, including roads and bridges; severe strain on roads and other physical infrastructure; roads no longer accessible by car due to damage caused by heavy trucks and machinery; housing shortages or lack of affordable housing (Brasier & Filteau, 2010); effects on the local tax base and on public services including schools, police, fire and jails; increased workforce development costs for an educated Marcellus workforce; opportunity costs and effects on competing industries, such as tourism and agriculture; and possibly, long term public health costs from air and water pollution, some predicated on the public's prior knowledge of various long-term impacts from mining and its remediation.

Future research should better explore many of these impacts as they result from exploitation of the Marcellus Shale. To date, we see evidence of some of these impacts in a variety of ways:

- housing shortages or lack of affordable housing (Brasier & Filteau, 2010, Bradwell, 2011),
- hundreds of construction jobs for steel plants fabricating materials for Marcellus Shale drilling and extraction (Toland, 2011; Guzzo, 2010),
- hundreds of new jobs in these steel plants (Toland, 2011),
- home renovations and new car purchases by leaseholders (industry employees, personal communication, 2011),
- $6.8 million in federal grants for infrastructure upgrades to a group of railroads in central Pennsylvania (Boyd, 2011).

A better understanding of the actual indirect and induced effects, rather than just those predicted by econometric models, can provide additional understanding of the extent and impact of the economic flows from Marcellus Shale drilling and production.

7 Conclusion

Why the rush to develop the Marcellus Shale? Horizontal drilling and hydraulic fracturing have made the extraction of natural gas from the Marcellus Shale to be fiscally feasible. Economically available natural gas extracted from within the U.S. has the potential to supply energy needs with domestic natural gas. When asked about this, Professor Ed Rubin of Carnegie Mellon University responded, “There is no need to rush. The gas has been there a long time. It'll be there six months from now, it'll be there a year from now. I think it's critical that the development of this resource be done thoughtfully, carefully, safely and in a way that engenders public trust.” (Majors, 2011).

This study has attempted to add to this awareness by examining the process of natural gas extraction from the Marcellus Shale, in terms of examining the direct economic impact of a single Marcellus Shale horizontal well site. These costs are summarized in Table 12.

Table 12 – Estimated total cost of a Marcellus Shale well

Feature Description	
ACQUISITION & LEASING	$2,191,125
PERMITTING	$10,075
SITE PREPARATION	$400,000
VERTICAL DRILLING	$663,275
HORIZONTAL DRILLING	$1,214,850
FRACTURING	$2,500,000
COMPLETION	$200,000
PRODUCTION TO GATHERING	$472,500
Total	**$7,651,825**

In summary, while the costs are significant, the development of a Marcellus Shale well is likely to have considerable economic impact on the region. The central costs in development are: site preparation and reclamation (nearly 2/5ths of total cost), mobilization of equipment and materials, including drilling rigs and hydraulic fracking equipment, power generation throughout the process, and steel and steel derivatives. The economic benefits are significant, both direct, which this report addressed, as well as indirect and induced economic benefits, not addressed in this report.

For some exploration and production firms, they have a reliance on rented or sourced equipment and human resources, allowing individual firms to focus on their core competencies and making available opportunities for specialized entrepreneurial ventures to take part in the value chain.

Government plays a critical role in regulating the industry and changes to the current laws and regulations are still being considered in Pennsylvania. New regulations or changes to the existing laws and regulations could have a future impact on the costs of drilling and operating a Marcellus Shale well, and would certainly impact the value chain as the production companies address issues of compliance. This is one clear example of why the direct economic impact analysis captured in this study is accurate as of the time of the study, but may vary over time in the future as regulatory costs, compliance costs, inflationary pressures, or changes in costs of materials or labor will change the total direct economic impact of a Marcellus Shale well.

Acronyms & Abbreviations

ADR	Alternative Dispute Resolution
API	American Petroleum Institute
Bcf	Billion cubic feet
BHA	Bottom Hole Assembly
CBA	College of Business Administration
CHK	Chesapeake Energy Corp,
CHKM	Chesapeake Midstream Partners
DEP	Department of Environmental Protection
DOT	Department of Transportation
FY	Fiscal year
HBP	Held By Production
LCA	Labor Condition Application
Mcf	Million cubic feet
NGL	Natural gas liquid
PA	Pennsylvania
PADEP	Pennsylvania Department of Environmental Protection
SRBC	Susquehanna River Basin Commission
Tcf	Trillion cubic feet
TMD	Total Measured Depth
TVD	Total Vertical Depth
USCIS	U.S. Citizenship and Immigration Services

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Appendix A – Cost Comparison: Vertically-Integrated Firm

While the direct economic impacts in this report were estimated using costs for exploration and production companies that extensively make use of service providers to provide much of the equipment and labor, this section examines the cost structure of a firm that emphasizes low costs and vertical integration (Chesapeake, 2011).

A.1 Introduction of Chesapeake's Vertical Operation Structure

Chesapeake Energy Corp. (CHK)[27] is the second-largest producer of natural gas, a Top 15 producer of oil and natural gas liquids and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Haynesville, Marcellus and Bossier natural gas shale plays and in the Eagle Ford, Granite Wash, Cleveland, Tonkawa, Mississippian, Wolfcamp, Bone Spring, Avalon, and Niobrara unconventional liquids plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets.

In Marcellus Shale, different from most companies drilling at Marcellus Shale, Chesapeake not only directly controls the engineers and technicians for drilling a Marcellus well, but also owns the rigs which it operates in its drilling business, provides the rental service of rigs and drilling equipment to other drilling companies and owns the Chesapeake Midstream Partners (CHKM) to vertically integrate the after-production gas gathering steps into its business scope. Chesapeake claims that "Focus on Low Cost" is the first drive for taking the vertical integration structure, "By minimizing lease operating costs and general and administrative expenses through focused activities, vertical integration and increased scale, we have been able to

[27] http://www.chk.com/Pages/default.aspx

deliver attractive profit margins and financial returns through all phases of the commodity price cycle."[28] To reduce the manufacturing risk is another concern in taking the vertical integration.

This Appendix estimates the costs occurring at each step of the value chain from acquisition of the land until the production to gathering. By comparing Chesapeake's costs and an average drilling company's costs in Marcellus Shale well establishment, we can observe the benefits and disadvantages of the two business organizational models in terms of cost efficiency.

A.2 Cost Comparison and Analysis

Generally, there are 8 steps in establishing an average Marcellus Shale well. These are

1. Acquisition & Leasing
2. Permitting
3. Site Preparation
4. Vertical Drilling
5. Horizontal Drilling
6. Fracturing
7. Production
8. Production to Gathering

Our estimates of the cost of each phase are based primarily upon data from Chesapeake's 2010 financial report 10-K released on March 1, 2011.

A.2.1 Acquisition and Leasing Cost

Chesapeake Energy Corp. (CHK) initiated a plan to build and maintain the largest inventory of onshore drilling opportunities in the U.S. Recognizing that better horizontal drilling and completion technologies, when applied to various new unconventional plays, Chesapeake would likely create a unique opportunity to capture decades worth of drilling opportunities, and they embarked on an aggressive lease acquisition

[28] Page 4, 10K, March 2010, Chesapeake

program, which have been referred to as the “gas shale land grab” of 2006 through 2008 and the “unconventional oil land grab” of 2009 and 2010. Chesapeake believed that the winner of these land grabs would enjoy competitive advantages for decades to come as other companies would be locked out of the best new unconventional resource plays in the U.S.

In 2010, the major land leasing and acquisition that Chesapeake conducted in the Marcellus Shale is listed as below[29]:

- Marshall Co., WV Leasing Activity ,June, 2010 - Chesapeake offered to lease a 53 acre parcel from the City of Moundsville located along the Ohio River in the Wheeling, WV metro area. The terms offered were $2,800 an acre and 18.75% royalty.
- The Highlands Leasing - The company leased land near The Highlands development in neighboring Ohio County, WV. Signing bonuses for the leases had run between $750/acre to $3,600/acre with royalties ranging from 12.5% up to 18.75%.
- Wetzel Co. acquisition - In September, 2010 the company was reported purchasing drilling rights to 22,000 acres in Wetzel County for $22 million ($1,000 per acre) from Ed Broome, owner of an oil and gas company in Glenville, WV.
- Anschutz acreage acquisition – In early November, 2010, Chesapeake was reported to have acquired 500,000 acres from Anschutz Exploration Corp first reported in October, 2010. The total amount of the transaction was $850 million.

According to the number provided by the above land leasing and acquisition activities, we can estimate the average leasing cost per 640 acres that Chesapeake paid in the Marcellus area.

2010 Acquisition and Leasing		
WV	=$2800*640=	1792000
Highland	=(750+3600)*640/2=	1392000
Wetzel	=$1000*640=	640000
Anschutz	=$850,000,000*640/500,000=	1088000
Average		**$1,228,000**

[29] http://www.waytogoto.com/wiki/index.php/Chesapeake_Energy#Anschutz_acreage_acquisition

Therefore, Chesapeake pays leasing cost around 1.23 million per 640 acres at this transaction. For an average Marcellus well, the paid up leasing cost per 640 acres is 1.93 million (see Table 2).

We assume the other costs, such as land-man labor cost is the same for leasing a well in the Marcellus Shale area by a company that is not vertically integrated. For more details, please refer to Section 5.2.1. The leasing term is 3 to 5 years according to the description in 10-K, March 2011 of the Chesapeake.[30]

A.2.2 Permitting Cost

Permitting costs are regulatory costs that are consistent across exploration and production firms within Pennsylvania, so permitting costs were assumed to be the same for the purpose of this analysis. For more details, please refer to Section 5.2.2.

A.2.3 Site Preparation

Site preparation costs were assumed to be the same for a Marcellus Shale well in Southwestern Pennsylvania for the purpose of this analysis. For more details, please refer to Section 5.3.

A.2.4 Total Drilling Cost

The drilling costs include the vertical drilling, horizontal drilling and fracturing costs. According to 10-K, 2011[31], "Marcellus Shale. Chesapeake's Marcellus Shale proved reserves represented 860 Bcf, or 5%, of our total proved reserves as of December 31, 2010. During 2010, the Marcellus Shale assets produced 53 Bcf, or 5%, of our total production, and we invested approximately $380 million to drill 329 (135 net) wells in the Marcellus Shale, net of $601 million in drilling and completion cost carries paid by our industry participation partner, Statoil, in 2010. For 2011, we anticipate spending

[30] Page 14, 10-K, 03/01/2011, Chesapeake

[31] Page 6, 10-K, 2011

approximately $325 million, or 6% of our total budget, for exploration and development activities, net of carries, in the Marcellus Shale. Statoil will pay 75% of our drilling and completion costs in the play until $2.125 billion has been paid, which we expect to occur by year-end 2012. Of the $1.362 billion drilling cost carry remaining at December 31, 2010, we expect approximately $660 million will be utilized in 2011."

In drilling the well, Chesapeake always cooperated with another company to form a joint venture, to drill and share the interest together. In Marcellus Shale, Chesapeake and Statoil co-invest 981 million (380 + 601= 981) to drill 329 wells together. Average drilling cost per well is 2.98 million.

A.2.5 Fracturing Cost

Chesapeake's 10-k, March 2011, suggests that during 2010 and 2009, Frac Tech Holdings, LLC, the 26% self-owned affiliate, provided Chesapeake hydraulic fracturing and other services in the ordinary course of business. During 2010 and 2009, Chesapeake paid Frac Tech $89 million and $43 million, respectively, for these services. As of December 31, 2010 and 2009, Chesapeake had $30 million and $8 million, respectively, due Frac Tech for services provided and not yet paid.[32]

According to the above information, in 2010, the total payment due for the fracturing should be $119 million.

A.2.6 Production Cost

Chesapeake's 10-k, March 2011, indicates that "Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $893 million in 2010, compared to $876 million and $889 million in 2009 and 2008, respectively. On a unit-of-production basis, production expenses were $0.86 per mcf in 2010 compared to $0.97 and $1.05 per mcf in 2009 and 2008, respectively. The per unit expense decreases in 2010 and 2009 were primarily the result of completing new high volume wells with lower per unit production costs."

[32] Page 57, 10-K, 2011

We assume that a well's annual production quantity is 1.3 million mcf, resulting in a production cost per well of $1,118,000.

A.2.7 Production to Gathering Cost

During 2010, Chesapeake Midstream Partners, L.P. (CHKM), the 42%-owned affiliate, provided natural gas gathering and treating services in the ordinary course of business. On September 30, 2009, our Predecessor formed a joint venture with Global Infrastructure Partners – A, L.P., and affiliated funds managed by Global Infrastructure Management, L.L.C., and certain of their respective subsidiaries and affiliates ("GIP"), to own and operate natural gas midstream assets. As part of the transaction, the Predecessor contributed certain natural gas gathering and treating assets to a new entity, Chesapeake Midstream Partners, L.L.C. and GIP purchased a 50 percent interest in the newly formed joint venture. The assets contributed to the joint venture and ultimately the Partnership were substantially all of our Predecessor's midstream assets in the Barnett Shale region and certain of its midstream assets in the Arkoma, Chesapeake, Delaware and Permian Basins. Subsidiaries of our Predecessor continued to operate midstream assets outside of the joint venture. At December 31, 2010 these included natural gas gathering assets primarily in the Fayetteville Shale (Chesapeake announced the proposed sale of its Fayetteville assets in February 2011), Haynesville Shale, Marcellus Shale (including other areas in the Appalachian Basin) and the Eagle Ford Shale. As of December 31, 2010, Chesapeake already paid CHKM $378 million, and still had a net payable to CHKM of $45 million. Since the income of the CHKM is almost the gathering revenue serving for the chesapeake. Therefore, we assume the total payment for CHKM is $378 + $45 = $423 million. As of Dec 31, 2010, CHK has gross acres of 408000[33] at Marcellus, producing 5% of the total gas production. Therefore, we can estimate the average after-production cost is 423 * 5%*640/ 408000=$33,177 per 640 acres.

[33] Page 15, 10-K, CHK, March 2011

A.3 Estimate of Costs for a Vertically Integrated Producer

In conclusion, the estimated total cost of a Chesapeake Marcellus Shale well is summarized in Table A-1 on the following page.

Table A-1 – Estimated total cost of a Chesapeake Marcellus Shale well

Feature Description	
ACQUISITION & LEASING	$1,228,000
PERMITTING	$10,075
SITE PREPARATION	$400,000
DRILLING (VERTICAL & HORIZONTAL DRILLING)	$2,981,763
FRACTURING	$361,702
PRODUCTION	$1,118,000
PRODUCTION TO GATHERING	$33,176
Total	**$5,722,642**
2010 Acquisition and Leasing	
WV	1792000
Highland	1392000
Wetzel	640000
Anschutz	1088000
Average	$1,228,000.00
2010 Drilling Cost	
Chesapeake Investment	380000000
Statoil	601000000
# of Gross Wells drilled in 2010	329
Drilling cost per well	$2,981,762.92
2010 Fracturing Cost	
2010 paid	$89,000,000
2010 due	$30,000,000
# of Gross Wells drilled in 2010	329
Fracturing Cost per Well	$361,702.13
2010 Production Cost	
Cost per Mcf	$0.86
Quantity of Production	1,300,000
Production Cost Per well	$1,118,000
2010 Production to Gathering (CHKM)	
Gas Gathering Fee	$378,000,000
Payment Due	$45,000,000
Total Cost for Gathering and other after-production service	$423,000,000
Production Percentage	5%
total gross Acres at Marcellus	408000
After- Production Cost Per 640 acres	$33,176.47

Appendix B – About the Research Team

William E. Hefley, Ph.D., CDP, COP, is a clinical associate professor of business administration in the Joseph M. Katz Graduate School of Business and College of Business Administration (CBA) at the University of Pittsburgh. A member of the Decision, Operations and Information Technology faculty at Pitt Business, Bill teaches in the MBA and MS MIS programs, including the graduate Global Supply Chain Management Certificate; as well as in the undergraduate programs in CBA, including the Certificate in Supply Chain Management and International Internships. During AY 2010-2011, he served as the faculty coordinator for supply chain/value chain initiatives at Pitt Business.

Shaun M. Seydor, Director of PantherlabWorks, Institute for Entrepreneurial Excellence, engages in focused business consulting for start-up entrepreneurs as well as existing companies. The PantherlabWorks program focuses on energy, sustainability, and emerging technologies. These initiatives encompass a broad array of emerging entrepreneurial opportunity, including renewable forms of energy, natural gas, green certifications, waste reduction strategies, inventions, and intellectual property.

Michelle K. Bencho, Ian Chappel, Max Dizard, John Hallman, Julia Herkt, Pei Jiuan Jiang, Matt Kerec, Fabian Lampe, Christopher L. Lehner, and Tingyu (Grace) Wei were Katz MBA students taking part in this research project, while Bill Birsic, Emily Coulter, Erik M. Hatter, Donna Jacko, Samuel Mignogna, Nicholas Park, Kaitlin Riley, and Tom Tawoda were undergraduate CBA business students actively involved in this project.

Eric Clements and Roman Harlovic contributed as student intern consultants, with the PantherlabWorks Program, at the Institute for Entrepreneurial Excellence. In their work as contributors to this study, they represent the Katz Graduate School of Business and the CBA, respectively.

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