Integrative Design of EME 580 Systems

Report on

Sustainable Development and Design of Marcellus Shale Play in Susquehanna, PA

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1.1. INTRODUCTION

Natural gas prices have steadily increased over the past few years. This has spurred interest in the development of “unconventional” gas resources, such as gas shales (1). *Conventional gas* reservoirs are areas where gas has been “trapped.” This gas is relatively easy to extract, as it will naturally flow out of the reservoir when a well is drilled while *Unconventional gas* occurs in formations where the permeability is so low that gas cannot easily flow (e.g., tight sands), or where the gas is tightly adsorbed (attached) to the rock (e.g., coal bed methane). Gas shales often include both scenarios - the fine-grained rock has low permeability; and, gas is adsorbed to clay particles. (2)

The U.S. Energy Information Administration projects that by 2030, half of the natural gas produced in the U.S. will be from unconventional sources. (3) In 2005, approximately 10 trillion cubic feet (TCF) of conventional gas was produced in the U.S., versus 8 TCF of unconventional gas. (4) Natural gas from shale accounted for about 6% of the gas produced in the U.S. (1.1 TCF). (5)The majority of U.S. gas shale production came from four basins: (6)

- San Juan Basin, New Mexico/Colorado - 55 million cubic feet per day (mmcf/d)
- Antrim Shale, Michigan - 384 mmcf/d
- Appalachian/Ohio shales – 438 mmcf/d
- Barnett Shale, Fort Worth Basin, Texas - 1,233 mmcf/d

Exploratory gas-shale drilling is occurring across the country. Some of the areas include: the Devonian shale in the Appalachian Basin; the Mowry shale in the Powder River Basin; the Mancos shale in the Uinta Basin; the Woodford shale in the Ardmore Basin; a Floyd/Neal shale play in the Black Warrior Basin; the Barnett shale in the Permian Basin; the New Albany shale in the Illinois Basin; and others. (7) This report focuses on the ***Marcellus shale***, located in the Appalachian region. This report has been completed for **Sustainable Development and Design of Marcellus Shale Play in Susquehanna, PA**. This report will highlight some of the potential issues that may be important to consider if full-scale development occurs in the Marcellus shale. This report will put emphasis over Environmental issues associated with Marcellus shale drilling. Guiding policy and regulations will be discussed in detail.

1.2. MARCELLUS SHALE

Shale is the common name for rock that was once layers of clay or mud. Due to geological circumstances, these layers were compressed into a fine-grained sedimentary rock. Marcellus is a Devonian-era shale, which means it originated approximately 350 – 415 million years ago. During that time, a lot of algae and other organisms died and fell to the bottom of the sea. These organisms provided carbon, which has since been converted into hydrocarbons, such as methane gas and crude oil. Illinois' New Albany shale, Michigan's Antrim shale, and Appalachia's Marcellus shale all date from this period. (8) Marcellus deposition cycle is most carbonate rich than any other shale deposition. (9) In many organic shale reservoirs, the natural gas is stored as free gas in fractures, and as absorbed gas on kerogen and clay surfaces within the shale matrix. (10) All rocks have pore space that can hold water or gases. In shales, the grains fit together so tightly that there is little movement of water or gas through the rock. In order for gas to be released, especially in "commercial" quantities, the shale must either have natural fractures, or fractures must be created in the rock (11).

1.2.1. LOCATION

The Marcellus shale spans a distance of approximately 600 miles, (12) running from the southern tier of New York, through the western portion of Pennsylvania into the eastern half of Ohio and through West Virginia. (see ***Figure 1***) (13) The areal extent of the Marcellus shale is about 54,000 square miles, (14) which is slightly larger than Florida. The shale is extremely variable in thickness, ranging from a few feet to more than 250 feet in thickness, (15) and generally becomes thicker to the east. (see ***Figure 2***) (14)

1.2.2. GEOLOGY

Black, organic-rich shales are common constituents of sedimentary deposits formed throughout geologic time. In Pennsylvania, black, organic-rich shales can be found in almost all of the Paleozoic systems, as well as in the Triassic rocks of the Newark and Gettysburg basins in the southeast. Some of these shales are the sources of the crude oil and natural gas found in Pennsylvania's sandstone and carbonate reservoirs. (16) Organic-rich shales (Marcellus) have higher radioactivity responses (17) greater than 10 parts per million and that may approach 100 parts per million. (18) The Marcellus shale is said to have "favorable mineralogy" in that it is a lower-density rock with more porosity, which means it may be filled with more free gas. (19)

- The Marcellus Formation underlies most of Pennsylvania, but the organic-rich portion reaches its maximum development in the northeastern part of the state. (16) Despite the long history of gas shows in the Marcellus, it took until recently for its potential as a commercial gas target to attract attention. (as shown in ***Figure 3***)
- The Marcellus formation is variable in depth and in some areas of New York it outcrops (appears at the surface). The Marcellus shale was actually named for an outcrop found near the town of Marcellus, NY, during a geological survey in 1839. (14) The majority of the Marcellus shale, however, is more than a mile deep, and in some areas it extends 9,000 feet below the surface.

The depth of Marcellus in Pennsylvania increases from North-East to South-West (19). (Refer ***Figure 2***)
- The east side is deeper and thicker, with a higher quartz content (more brittle), but has a lower organic content (19).

1.2.3. POTENTIAL OF MARCELLUS GAS RESOURCES

It has been conservatively estimated by Dr. Terry Engelder, a Pennsylvania State University geosciences professor and Dr. Gary Lash, professor of geosciences, SUNY Fredonia, that the entire Marcellus shale contains 168 trillion cubic feet (TCF) of ***gas in place***. Engelder's more optimistic estimate is that it could contain 516 TCF. (13) When so-called experts calculate the size of a gas reserve, they usually consider only 10 percent of gas in place as being ***technically recoverable***. (20)So, on the low size, the Marcellus shale is a potential resource of 16.8 TCF, and on the high side 50 TCF. In 2006, the U.S. consumed more than 21 TCF of natural gas. (21) So, if the estimates by Engelder and Lash are correct, gas from the Marcellus shale could support this level of consumption for 1 to 2.4 years.

1.2.4. GAS OCCURRENCE IN THE ROCK

"Natural gas occurs within the Marcellus Shale in three ways:

- Within the pore spaces of the shale;
- Within vertical fractures (joints) that break through the shale; and,
- Adsorbed on mineral grains and organic material.

Most of the recoverable gas is contained in the pore spaces. However, the gas has difficulty escaping through the pore spaces because they are very tiny and poorly connected" (22)

1.2.5. GAS TRANSPORT IN MARCELLUS SHALE MATRIX

Most historic wells in the Marcellus produced gas at a very slow rate because of the low permeability. This is typical for shale. "These and related characteristics led exploration geologists to conclude, after years of lively debate, that the black shales were the source of gas in the shale sequence and that much of the gas produced during the initial flush-production phase was contained in an extensive network of natural fractures cutting the gas shale sequence. Gas produced during the long period of slowly decreasing decline came from the shale matrix by slow desorption into the fracture system and was in a dynamic equilibrium with the well's ability to yield gas at the existing reservoir pressure. The well bore must penetrate the natural fracture system or be linked to the fracture system by permeable pathways established by the well-stimulation techniques for production". (23) In a newly drilled well that intersects the fracture system, gas escapes rapidly from the relatively permeable fractures. Eventually, the volume of gas desorbing from the organic matter in the matrix of the shale and moving slowly through the low permeable shale into the fracture system balances the volume of gas passing from the fractures into the well bore.

1.3. DRILLING

To extract natural gas from Marcellus Shale, one should consider that every drilling method, equipment, material, location and other conditions are matched to the properties and characteristic of the gas shale. And there are several ways to increase gas recovery such as horizontal drilling and hydraulic fracturing.

1.3.1. DRILLING METHODS

Two types of drilling methods, (as shown in ***Figure 4***), vertical and horizontal are being used in the Marcellus Shale (24). Range Resources, as a pioneer E&P company drilled 200 vertical wells and 50 horizontal ones in the Marcellus in 2008. They are planning to drill 200 more vertical wells and 250 horizontal ones in 2009 (25).

1.3.1.1. VERTICAL DRILLING

Vertical drilling is traditional type of drilling in oil and gas drilling industry. Mountains, seas, lakes and accommodation areas are the limitations for vertical drilling, which makes it impossible and extremely expensive.

Limitations of Vertical Drilling

Vertical well can reach only a single spot of the shale reservoir. (see ***Figure 5***)

- In Marcellus Shale, there are vertical fractures. Therefore, drilling a standard vertical well limits the frequency of intersecting a large number of the fractures. Therefore, decreases the chance and high volume of retrieved gas (26).

1.3.1.2. HORIZONTAL DRILLING

Most of gas wells were vertical before major drilling companies such as Halliburton, Devon Energy, Rex Energy and Range Resources started focusing on the horizontal drilling (27). Horizontal drilling is the same as vertical drilling until the "kickoff point" which is located just above the target oil or gas reservoir, from that point deviating the drilling direction from the vertical to horizontal (angle between 70 and 110 degrees (28)) to intersect the reservoir at the "entry point" with a almost-horizontal inclination, and remaining inside of the reservoir until the drilling is reached to desired location. (29)

Benefits of Horizontal Drilling

Productivities of horizontal wells are generally at least 2 or 3 times the productivity of vertical wells. For old vertical wells which already been considered uneconomic, a horizontal drilling often accomplishes successful development of the reservoir. Some types of oil and gas reservoirs can be only recovered by horizontal drilling. Horizontal drilling has the following benefits (30; 25; 31; 32) :

- Most oil and gas reservoirs are much more extensive in their horizontal dimensions (thin reservoir) than in their vertical dimension. So, if we use vertical drilling, we only can extract oil and gas from a small area just surrounding the wellbore. However, horizontal wells could reach these flat reservoirs.
- Horizontal drilling can enormously reduce surface impact, because this method enables us to drill several wells from a single surface location.
- It provides maximum contacts with the gas-bearing rock formation, so that more gas can be produced from a single well.

1.3.2. LAND FOR DRILLING OPERATION IN MARCELLUS

To drill a vertical or horizontal well in a region, the drilling company/operator needs to lease the appropriate land, acquire drilling permit and install appropriate equipments and facilities in the site.

Both Vertical and Horizontal well drillings are used in Marcellus Shale. However because of the natural low permeability of the shale; vertical wells must be developed at closer spacing intervals. This results drilling more gas wells, meaning more well pads, access roads, pipeline routes, and production facilities, which cause more soil disturbance and have greater impact on public and environment. Devon Energy Corporation reports on the development on Barnett Shale shows that they could replace 3 or 4 vertical gas wells with one horizontal well (33). Thus, based on the information from other gas shale basins, we can assume that using horizontal drilling there will be less soil disturbance. ***Table 1***, and *"Daniel Johnston book"* (34) suggest the well spacing and design of vertical or horizontal drilling in Marcellus Shale. *"When a new natural gas field is developed, well spacing depends on the state's regulations. It is common for operators to be allowed one well per section (640 acres) or drilling unit, unless they can prove to state regulators that more wells are required to extract as much of the gas resource as possible."* (24)

1.3.3. DRILLING FLUID

Drilling fluid is one of important components in drilling process. A fluid is required in the drilling process to (35; 31):

- Cool and lubricate the drilling bit and string using circulation.
- Clean the bottom of the hole under the drilling bit.
- Transport the cuttings to the surface and drop off the cuttings on the surface.
- Control subsurface pressure and stabilize the borehole before casing.

1.3.3.1. DRILLING FLUID TYPES IN MARCELLUS SHALE

Depending on the drilling conditions, different types of drilling fluids can be used in shale (36; 31):

- Water-based muds (WBMs)
- Oil-based muds (OBMs)
- Synthetic-based muds (SBMs)
- Air and foam fluids

Drilling mud will be used in drilling in the Marcellus shale zone. According to the Oil and Gas Accountability Project, "Drilling fluids or mud are made up of a base fluid (water, diesel or mineral oil, or a synthetic compound); weighting agents (most frequently barite is used); bentonite clay to help remove cuttings from the well and to form a filter cake on the walls of the hole; chrome lignosulfonates and lignites to keep the mud in a fluid state; and various additives serve specific functions, such as biocides, diesel lubricants and chromate corrosion inhibitors" (36).

1.3.3.2. DRILLING FLUID TYPES IN OTHER SHALE

In certain area of Barnett Shale, drillers use fresh water mud and water-based mud with additives such as lime, gel, polymer, soda ash, sodium bicarbonate, barite, detergent and etc... (37). In some other areas of Barnett Shale, in the Delaware Basin, oil-based drilling mud is used to prevent borehole stability problems (38). In certain area of Devonian Shale, drillers use oil-based drilling fluids with conventional rotary drilling (39). Also, in certain area of San Juan Basin, drillers use air as drilling fluid (40). Drilling fluid type is strongly related to the components of the part of certain shale. Through the analysis the composition of the shale, the drillers find the optimal drilling fluid for drilling. However, for the gas shale, air drilling is a technique widely used (41) .

1.4. COMPLETION

After a well is drilled, the next operation is completion of the well for production. Completion and drilling operations are both undertaken with the view of stimulating the well. The stimulation method of choice is hydraulic fracturing. Drilling can be done either in the horizontal and/or vertical direction. Drilling and Completion does play a lesser role in stimulation design for a vertical well as compared to a horizontal well. (42) Initial tasks include:

- Determining the hydraulic fracture direction
- Formation-related issues
- Casing/ completion selections
- Available solutions for the life of the well

As in any commercially viable reservoir the thickness of the reservoir is always lesser than the effective radius. To achieve maximum production, drilling should be in the direction of the minimum principal stress to create fractures in transverse direction. So it is important to know whether stimulation is needed before drilling and completion (42).

Most of the horizontal wells drilled worldwide are completed as open hole. High pressure cannot be applied in open hole completions which is required for stimulation so casing and cementing is preferred. The various factors taken into consideration while designing casing are setting depths, pressure, environment, thermal expansion, pressure changes, piston effects and their resultant force and/or length changes, drag and torque, formation subsidence, effect of perforations and bending loads (43; 44). An advanced technique used in the shale plays is the multi zone completion where one can produce and/or stimulate zones of interest (45).

1.5. STIMULATION

Hydraulic fracturing and horizontal drilling are the key technologies that made natural gas recovery from shale economically viable in the Barnett Shale in the 90's (46). Based on experiences in other gas shale regions where development is in more advanced stages like in the Barnett Shale, this technology can be used to further develop other shale plays. However the best practices are eventually developed locally. (46) To obtain commercial production from the low permeability (47) Marcellus shale fracture stimulation (48) is necessary.

Fracture stimulation consists mainly of injecting acid, water or gases into the well to open up the natural fractures and/or to propagate new fractures into the formation thereby increasing the permeability of the formation. The various types of fracturing fluids used depend upon the geology of the formation and the availability of the fluid. The fluids used range from slickwater, hydrochloric acid to carbon dioxide and nitrogen (49). In shale, acid is not used as it is expensive as compared to water and mainly used in matrix acidizing i.e. removing skin formed due to drilling and completion operations. Also with using acid effective fracture length and drainage radius are not achieved. (50) Slickwater is the preferred fluid of choice in the Marcellus shale but a few advantages of using carbon dioxide instead of water are discussed and so it is more appealing to consider using carbon dioxide. Using a fluid like carbon dioxide reduces the amount of overall water needed for production and this has helpful effects. Carbon dioxide is a plentiful energy by-product while water is a valuable resource which can be used for other more important uses.

The technique of hydraulic fracturing was first introduced to the petroleum industry in a paper in 1948. (51) Carbon dioxide has been used in the Devonian Shale for stimulation in 1993 to give good results (52)after initially being used in 1960 (53) and with sand in 1982. (54) Theses stimulations were performed for vertical wells. The mechanisms behind the actual functioning of carbon dioxide in fracture creation and propagation in complex. It includes carbon dioxide as an energizing fluid, (55) corrosive interactions and also the preferential adsorption of carbon dioxide displacing methane. (56) Apart from using only Carbon dioxide it is possible to use Carbon dioxide blended with water and other fluids to fracture the formation.

There are also a few commercially available fluids which use carbon dioxide as a fracturing fluid. These use carbon dioxide as in the liquid or supercritical phase. When an emulsion is formed with gels they form foam and this is what is generally used in fracturing. Generally the foam will contain about 60-80% carbon dioxide. (57) Also various surfactants are added to the foams along with the gels for lowering surface tension and friction pressure so the fluid can travel deep into the fracture. (58) Dry ice has also been used in the past to drive fractures into rock. (59) The phase change from solid carbon dioxide to gaseous carbon dioxide results in a large increase in volume. The gas expands and as a result there is an increase in pressure which drives the fracture. Using carbon dioxide in the liquid phase has a similar effect in driving the fractures as dry ice. (60)

Carbon dioxide when compressed and cooled forms a liquid. The critical temperature of carbon dioxide is 88°F. (55) Above this temperature carbon dioxide exist only as a dense vapor irrespective of the pressure. Solubility of carbon dioxide in water and hydrocarbons is also good. Carbon dioxide dissolves in water to form weak carbonic acid. Carbonic acid dissolves carbonates minerals in rocks creating fractures. Also it acts to buffer the pH of an aqueous solution. Carbon dioxide also has another advantage with respect to wellbore dynamics. (61) Due to carbon dioxide's larger compressibility and expansivity as compared to water it would increase buoyancy forces which in turn would lead to less parasitic power consumption in pumping fluid down the wellbore. Production is often controlled by desorption of gas, rather than matrix flow (62).

Due to the peculiar physical and chemical properties of carbon dioxide, it has some advantages (63). They are:

- Eliminates swabbing in most cases
- Provides rapid clean-up which helps remove mud, silts, etc.
- Removes or prevents water and emulsion blocks
- Retards acid reaction with formation
- Helps prevent clay swelling and precipitation of iron and aluminum hydroxides
- Reduces friction loss of oil-based fluids
- Increases permeability of carbonate formations

Methanol and methanol based emulsions with carbon dioxide and water are also being used as a fracturing fluid in low-permeability gas reservoirs. (64) Some of the favorable effects of adding Methanol other than reducing the amount of water needed are:

- Lowering of surface tension
- Lowering of freezing point of water
- Lowering of the specific gravity
- Increasing the vapor pressure
- Increasing the viscosity

The geology of the Marcellus Shale and the high TOC make the use of carbon dioxide as a fracturing fluid workable. (65) Also the availability of ample carbon dioxide from the coal fired power plants will mean that carbon dioxide supply will not be a problem. Sand (52) has also been used successfully as a proppant with carbon dioxide and so effect on proppant by carbon dioxide can be neglected. Using carbon dioxide also has an advantage that after the proppant has been placed, due to the pressure drop the carbon dioxide turns to gas and this allows for fracture fluid to be produced back at a higher rate. (66) Also high percentage of carbonate minerals in shale can be dissolved by carbonic acid which is formed with injection of carbon dioxide. (50) Carbon dioxide has also been added to fracture fluids in shale to assist in fluid recovery. (67)

1.5.1. TECHNOLOGY

The advance multi-zone technology developed by Exxon-Mobil is ideal for enabling economic recovery of multi-zone unconventional resources like the Marcellus shale. (68) The two technologies include "Just-in-Time Perforating" and "Annular Coiled tubing Fracturing". Achieving desired "ball-out" is a concern in JITP method so ACT-Frac is preferred. This coupled with "Tailored Pulse Fracturing" (69)or "Hydrajet-fracturing" (70) leads to effective well stimulation and eventually commercial production.

1.5.2. HYDRAULIC FRACTURING FLUID

Millions of gallons of water-based fracturing fluids mixed with proppant materials are pumped above the fracture pressure to target the shale formation (71). In addition to water and proppant, i.e. sand, many other additives for different purposes, such as reducing the friction, are used in this process. ***Table 2*** presents different types of additives, which interestingly are items that people encounter in their daily lives (72).

1.5.2.1. CHEMICALS

Up to 54 substances are used accompanying with water for fracturing the shale. Some of them are used to reduce friction in the process, some, like pesticides, to kill algae in ponds and tanks built next to the drilling pads, since they can ruin the water pumps. Although operators are required to submit a list of these chemicals as a part of their permit application, they are not required to disclose the amount they are using. So basically no information about the amount and concentration of arsenic, manganese, cobalt, chromium and lead is available to DEP to be able to evaluate a company's risk of endangering the environment. Depending on the concentration of the chemicals, if one is exposed to the contamination they can irritate his/her skin, or eye or even damage one's kidney, heart, liver or lung function. Toxic chemicals like pesticides can also affect aquatic life (73).

1.5.2.2. WATER AVAILABILITY, POLLUTION AND DISPOSAL

The Appalachian area with its precipitation of approximately 43 inches receives 10 inches more per year than the average for the continental United States (74). This precipitation is evenly distributed over the course of the year. It results input of between 710,000,000,000 and 1,250,000,000,000 gallons of water in to Marcellus shale area. Comparing to other shale across the nations, Marcellus has substantially more water resources, making it the ideal area for gas development (72). Having this magnitude of precipitation creates great sources for groundwater in this area.

1.5.2.2.1. UNDERGROUND AND SURFACE WATER RESOURCES CONTAMINATION

One of the environmental concerns in this area is preventing the pollution of vital underground drinking resources. It is understood that the distance between where the gas is generated in the shale is far enough from the sources of ground water, however during the initial stages of drilling we pass through the groundwater level. To prevent penetration of the drilling fluids and other pollutants to the water sheds, state oil and gas agencies require operators to execute proper casing and cementing program, which needs to be submitted for attaining the drilling permit. In a study done for American Institute of Petroleum, it was shown that a number of independent events need to occur at the same time and remain undetected by both the operator and regulators for injected fluid (the pollutant) to reach Underground Source of Drinking Water (USDW) (75). “These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing], and the surface casing coupled with the unlikely occurrence of water moving along distances up the borehole past salt water aquifers to reach a USDW” (75). With performing high level of monitoring, it is expected to have a very low probability of impacting the USDW. It can be even less than $2*10^{-8}$, which was presented in the API’s research. Moreover, prior to any gas well drilling, drinking water supplies within 1,000 feet of the proposed gas well will likely be tested at no charge to the homeowner by a certified testing laboratory hired by the gas company. (76) Any change in the taste, color, or any bubble in the tap water needs to be reported to DEP offices for further investigation. (76)

Surface water is also in danger of pollution if any spill during drilling occurs. “Service companies who perform hydraulic fracturing stimulation work for operators are also working to design systems which allow fracturing fluids to be contained within closed systems which have been designed to keep all additives, fracturing fluids, mixing equipment and flow-back water within a storage tank, service truck or flow-line” (72). Not to mention that state oil and gas agencies require operators to report any spills, which need to be assessed by them. The agency’s assessment and associated paper work are potential cause of delay, which are not desirable for the operators.

1.5.2.2.2. WATER SUPPLY

Water is the primary component of hydrofracturing process. More than 90 percent of the fracture fluid is water (72). Millions of gallons of water are needed for each hydrofracturing process. Drillers withdraw water streams or lakes and store in storage pond or steel water tanks, located at the site. Because of the sufficient sources of fresh water in Pennsylvania providing this amount of water is not an issue, however managing and treating the flow-back water is the most important issue. Since it contains different types of chemicals and particles, it needs to be treated prior to discharge to surface streams. Exposure of those chemicals to surface or underground sources of drinking water contaminates. These chemicals can be serious threats to human life. They can cause kidney diseases, cancer or other diseases. This contaminated fluid is also a threat to aquatic life. Some chemical can poison and kill the fish. That’s why environmentalists are so concern about the use of water and the contamination of the returned water

(77). Monitoring the quality of surface water is fairly easy, despite of gathering information regarding underground water resources (78). DEP conduct unannounced inspections to see if the operator is executing the proper wastewater management.

1.5.2.2.3. DISPOSAL OF FLOW-BACK FLUID

Flow-back and produced water from hydro-fracturing are captured and enclosed in containment tank or storage truck to reduce the exposure to the environment. Some operators recycle the fluid in the site and reuse it for the process. DTE Gas Resources, Inc. found this process uneconomic based on its study on two wells utilizing on site separation and filtration. (79). Most of the operators transport the fracwater to a waste water treatment facility and then discharge it to the streams, where as some are actively researching the option of pumping the flow-water into a very deep disposal well. This option has to meet the DEP's regulation. (72)

1.6. DRILLING POLICIES, REGULATIONS AND PERMIT

There are more than 350,000 drilled wells since 1859 in PA. Oil and gas laws (all or in part) have regulated exploration and drilling for oil and gas. They are 'The Clean Streams Law', 'The Dam Safety' and 'Encroachments Act' etc. There are several agencies like Pennsylvania Fish and Boat Commission, Susquehanna and Delaware River basin commissions that oversee the quality of water and aquatic life in Pennsylvania.

Oil and Gas Act of 1984 requires oil and gas companies to acquire a drilling permit, through an extensive permit application process. The application fee has changed from the flat rate of $100 to at least $250. It increases with depth and type of drilling. This permit is submitted to Pennsylvania Department of Environment Protection (DEP), who enforces the regulations. Drilling permit consists of many different parts, some of which are briefly listed below:

- A Map showing
- A bond ranging from $2,500-$25,000 to ensure compliance with environmental regulations (76)
- Specified sources and locations of water
- Impact of drilling on water resources
- The drinking water supplies within 1,000 feet to be tested by a certified testing lab
- Proof of approval from appropriate River Basin Commission, e.g., Susquehanna or Delaware River, if withdrawing water from them
- Permits or registration with DEP for more than 10,000 gallons/day water withdrawal

1.7. PRODUCTION IN MARCELLUS

Production rate in Marcellus Shale varies based on the region, the properties of that region as well as the capability of the drilling companies. There are several companies producing natural gas from

Marcellus Shale such as Range Resources, CNX Gas Co., Cabot Oil & Gas Corporation, Rex Energy, Atlas Energy and etc. ***Table 3***, shows average production rate of those companies.

1.8. NATURAL GAS PROCESSING AND TRANSPORTATION

The total U.S. marketed natural gas production is expected to rise slightly in 2009 and fall by 1.1 percent in 2010 whereas the total natural gas consumption is projected to decline by 1.3 percent in 2009 and then increase by 0.6 percent in 2010 according to the EIA source (80).

Natural gas, as it exists underground, is not exactly the same as the natural gas that comes through the pipelines to our homes and businesses. Natural gas, as we use it, is almost entirely made up of methane. However, natural gas that comes out of the well is although still composed primarily of methane (around 90-97%) (81), but doesn't means it is pure; mostly it contains hydrocarbons such as ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds, all of this are considered impurities and must be removed. This again raises environmental and waste management concerns.

The processing of natural gas consists of the separation of all the various hydrocarbons and fluids from the pure natural gas, to produce what is known as "pipeline quality" dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. This means that before the natural gas can be transported by pipeline, it must be purified to meet the requirement for the pipeline and the commercial uses. The associated hydrocarbons (ethane, propane, butane, pentanes and natural gasoline) known as 'Natural Gas Liquids' (NGLs) can be very valuable by-products after the natural gas has been purified and fractionated. NGLs are liquid natural gas at normal atmospheric pressure, but at underground pressures there occur in gaseous state.

The natural gas processing can be accomplished at or near the wellhead usually known as field processing. The complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these processing plants through a network of gathering pipelines. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area. The Energy Information Agency (EIA) and the Department of Energy (DOE) which are the authorities in the U.S. energy sector announced in its 2008 annual report that more than 85 U.S. interstate pipeline companies operate almost 200,000 miles of transmission lines, hundreds of compressor stations, and numerous storage facilities, allowing gas delivery throughout the lower 48 States. The importance of the network is reflected in the fact that 27 of the lower 48 States are almost totally dependent upon the interstate system for their gas supplies. Overall, the interstate natural gas pipeline grid consists of more than 155 Bcf per day of capacity and approximately 212,000 miles of pipeline.

There are also refinery plants that do the final processing and there are known as 'straddle extraction plants' and there are located on major pipeline systems. Although the natural gas that arrives at these straddle extraction plants is already of pipeline quality, in certain cases there still exist small quantities of NGLs, which have to be extracted at the straddle plants.

The processing of natural gas for pipeline dry gas quality levels and commercial uses usually involves different processes to remove the various impurities such as solids, free liquids and reduce water vapor content to acceptable levels. These four major processes are:

- Water removal
- Acid and gas removal
- Separation of condensates
- Fractionation of NGLs

1.8.1. WATER REMOVAL

The presence of water in natural gas stream may condense and cause the formation of hydrates depending on the temperature and pressure prevailing in an installation (82). The processes generally used for the water removal is the glycol dehydration using a solution of diethylene glycol or trietylene glycol, and the adsorption dehydratation using silica gel to perform the extraction.

1.8.2. ACID AND GAS REMOVAL

Hydrogen sulfide (H_2S) is very toxic and corrosive; the carbon dioxide CO_2 can be also corrosive and has no heating value. Those two compounds are dangerous for the environment and also for the pipeline. The process to remove these products is called the amine treating process. The process uses the monoethanolamine (MEA) or diethanolamine (DEA) to purify the natural gas stream. The chemical reactions are:

$2RNH_2 + H_2S \rightarrow (RNH_3)_2S$ $\quad$ $R = HOCH_2CH_2$

$2RNH_2 + CO_2 + H_2O \rightarrow (RNH_3)_2CO_3$ or

$2RNH_2 + CO_2 \rightarrow RNHCOONH_3R$

The H2S recovered can be converted to sulfur and sell in the market to chemical industry for the production of sulfuric acid. In fact according to the U.S. Geological Survey (USGS), the sulfur production from natural gas processing plants account for about 15% of the total U.S. production. The CO2 recovered can be also sold for enhanced oil recovery.

1.8.3. FRACTIONATION OF NGLS

If the natural gas contains a large fraction of hydrocarbons others than methane, it may be necessary to separate these hydrocarbons to avoid the formation of a liquid phase during transportation. The process used to separate the natural gas liquids into different fractions can be the fractionation by refrigeration or fractionation by low temperature distillation (82). The NGLs are more valuable as raw material to produce petrochemical and gasoline. Ethane, propane can be sold as liquefied petroleum gas and isobutane are used as blending components of high quality gasoline.

The efficient and effective movement of natural gas from producing regions to consumption regions requires an extensive and elaborate transportation system. In many instances, natural gas produced from a particular well will have to travel a great distance to reach its point of use. Transportation of natural gas is closely linked to its storage. This is because, in the event of the gas being transported is not required at that time, it can be put into storage facilities for when it is needed. Pennsylvania is one of the state that has higher storage capability after Michigan (12.62 %) and Illinois (11.67 %) in the nation. In fact the underground storage capacity for Pennsylvania is about 759 Bcf which is 9.04 % of the U.S capacity (83).

There are essentially three major types of pipelines along the transportation route: the gathering system, the interstate pipeline, and the distribution system. The gathering system consists of low pressure, low diameter pipelines that transport raw natural gas from the wellhead to the processing plant. Should natural gas from a particular well have high sulfur and carbon dioxide contents (sour gas), a specialized sour gas gathering pipe must be installed? Sour gas is extremely corrosive and dangerous, thus its transportation from the wellhead to the sweetening plant must be done carefully.

Pipelines can be characterized as interstate or intrastate. Interstate pipelines carry natural gas across state boundaries, in some cases clearly across the country. Intrastate pipelines, on the other hand, transport natural gas within a particular state. Interstate pipelines are the 'highways' of natural gas transmission. Natural gas that is transported through interstate pipelines travels at high pressure in the pipeline, at pressures anywhere from 200 to 1500 pounds per square inch (psi).This reduces the volume of the natural gas being transported (by up to 600 times), as well as providing propellant force to move the natural gas through the pipeline.

1.8.4. THE CRUCIAL LINK BETWEEN NATURAL GAS PRODUCTION AND ITS TRANSPORTATION TO THE MARKET

The natural gas product fed into the mainline gas transportation system in the United States must meet specific quality measures in order for the pipeline grid to operate properly. Consequently, natural gas produced at the wellhead must be processed before it can be safely delivered to the high-pressure, long-distance pipelines that transport the product to the consuming public. Natural gas that is not within certain specific gravities, pressures, Btu content range, or water content levels will cause operational problems, pipeline deterioration, or can even cause pipeline rupture (84).

The natural gas received and transported by the major intrastate and interstate mainline transmission systems must meet the quality standards specified by pipeline companies in the “General Terms and Conditions (GTC)” section of their tariffs. These quality standards vary from pipeline to pipeline and are usually a function of a pipeline system’s design, its downstream interconnecting pipelines, and its customer base. In general, these standards specify that the natural gas (85):

- Be within a specific Btu content range (1,035 Btu per cubic feet, +/- 50 Btu)
- Be delivered at a specified hydrocarbon dew point temperature level (below which any vaporized gas liquid in the mix will tend to condense at pipeline pressure)
- Contain no more than trace amounts of elements such as hydrogen sulfide, carbon dioxide, nitrogen, water vapor, and oxygen
- Be free of particulate solids and liquid water that could be detrimental to the pipeline or its ancillary operating equipment.

The processing of natural gas whether in the field or at refinery plants, assures that these requirements can be met. Generally the treatment facilities remove contaminants and heavy hydrocarbons from the gas stream; but in some cases they instead blend some heavy hydrocarbons into the gas stream in order to bring it within acceptable Btu levels. For instance, in some areas coal bed methane production falls below the pipeline’s Btu standard, in which case a blend of higher Btu-content natural gas or a propane-air mixture is injected to enrich its heat content (Btu) prior for delivery to the pipeline (86). More over in the case of LNG import facilities where the heat content of the re-gasified gas does not meet the pipeline specifications, vaporized nitrogen may be injected into the natural gas stream to lower its Btu content (86).

In recent years, as natural gas pricing went from a volume basis (per thousand cubic feet) to a heat-content basis (per million Btu), refiners have tended to increase the Btu content of the gas delivered into the pipeline grid while decreasing the amount of natural gas liquids recovered from the natural gas stream. Consequently, interstate pipeline companies have had to monitor and enforce their hydrocarbon dew point temperature level restrictions more frequently to avoid any potential liquid formation within the pipes that may occur as a result of producers maximizing Btu content. The dew point refers to the temperature at which a substance will condense from its gaseous or vapor phase into liquids.

1.8.5. NATURAL GAS PROCESSING COST RECOVERY

The primary role of a natural gas processing plant in the marketplace today is to produce natural gas that meets the specifications for pipeline transportation and for commercial uses. The production of natural gas liquids and other products from the natural gas stream is secondary. The quantity and quality of the byproducts produced is dependent their current market prices. If the market value of a byproduct falls below the current production cost, a natural gas plant owner/operator may suspend its production temporarily. In some instances, a plant operator may increase the Btu content of its plant residue (plant tailgate) gas stream, as long as it remains within pipeline tolerances, in order to absorb some of the byproducts (86) . In other cases the raw liquid stream without the methane is kept in storage temporarily or sold off. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy

1.8.6. UTILIZATION OF NATURAL GAS

The uses of natural gas are diversified. Natural gas is used in residential, commercial and in the industrial sectors. Natural gas can be also used for power generation. It is also increasingly used as an alternative transportation fuel. According to the American Gas Association, 5 trillion cubic feet is enough to meet the need of 5millions household for 15 years. Natural gas meets more than 22% of the total US demand. Also more than 62% of the US households use natural gas as their main heating fuel and for cooking. The different uses of natural gas in Pennsylvania are showed in ***Table 5***. In 2007 Pennsylvania consumed 752,321 million cubic feet (MMcf) and the production was only 182,277 MMcf (83).

Natural gas is also used as raw material for the production of petrochemicals, plastics, paints and other products. In industry some applications of the natural gas is for the production of steel and can be a power source. Natural gas has the advantage of replacing the use of coal and fuel oil because it burn clean and can help reduce the environmental impacts caused by the use of coal for instance in power plant generation and the use of crude oil for transportation fuel.

1.9. REGULATION AND POLICY OF PENNSYLVANIA STATE ON UTILIZATION

There are policies in place that protect people and environment. The policies are mainly focused on the environmental protection and the technology for clean energy.

1.9.1. OVERVIEW OF REGULATION HISTORY FOR GAS INDUSTRY

The regulation of Pennsylvania is not departed from Federal Regulation. Basically, the Federal Regulation of the gas industry started from the problem among municipalities. In the very beginning of the industry, the gas-producer did not need to sell the production to outside state consumers. As the industry and technology developed, the regulation developed and became complicated. And the Federal level regulations were needed to be involved to solve the problems.

The FERC (Federal Energy Regulatory Commission), under the Department of Energy Organization Act of 1977, is the main regulatory agency that oversees the natural gas industry since 1977. They have pursued the efficient management and consumer’s convenience with regulation and deregulation. They have issued several Orders like FERC Order No.436, which was for interstate pipelines, FERC Order No. 636 for the unbundling of pipeline services. Meanwhile, for deregulation of the wellheads of gas, the Natural Gas Wellhead Decontrol Act of 1989 was passed by Congress.

1.9.2. CURRENT REGULATION AND DEREGULATION

Under the current regulatory environment, only pipelines and local distribution companies (LDCs) are directly regulated with respect to the services they provide. Natural gas producers and marketers are not directly regulated. (87) But this does not mean that there are no regulations. Production and marketing companies must operate within the restrain of Local Act and environmental regulations. Local distribution companies are regulated by state utility commissions, which oversee their tariffs, construction issues, and ensure proper procedure exists for maintaining adequate supply to their customers. (87)

FERC oversees gas companies that have significant market power and is charging regulating the companies that do not abuse their monopoly position. FERC's regulatory have these objectives; (87)

- Preventing discriminatory or preferential service
- Preventing inefficient investment and unfair pricing
- Ensuring high quality service
- Preventing wasteful duplication of facilities
- Acting as a surrogate for competition where competition does not or cannot exist
- Promoting a secure, high-quality, environmentally sound energy infrastructure through the use of consistent policies
- Where possible, promoting the introduction of well functioning competitive markets in place of traditional regulation
- Protecting customers and market participants through oversight of changing energy markets, including mitigating market power and ensuring fair and just market outcomes for all participants

There are several important FERC regulations and Orders that rule the gas industry. They are FERC Order 636(released in 1992), 637(released in 2000), 639(released in 1999). Order 636 states restructuring of interstate pipeline service. Order 637 states the regulation of short term pipeline services. Order 639 is about the regulation of the movement of natural gas in the Outer Continental Shelf (OCS) of the U.S. Each Order is for the shaping the current regulation of interstate pipelines.

1.9.3. POLICY FOR GAS INDUSTRY

Pennsylvania State set up its own gas industry policy and has aims to meet. The policies are focused on reducing gas consumption and elevating energy efficiency. This can be achieved by tax incentives, fund for technology development and so forth. There are seven major policies including climate change roadmap and they are summarized as below;

Vehicle Policy of Pennsylvania State: Pennsylvania adopted California's Low-Emission Vehicle Program in 2006, committing to a 30% reduction in average new vehicle greenhouse gas emissions from 2002 levels by 2016.

Electric Utility Sector Policies: This policy is about energy efficient improvements. Currently there is only one utility energy efficiency program which is run by West Penn Power. The company provides loans so that the residential homeowners can invest into the energy efficiency elevation for their own house.

Tax Incentives: In July 2008, Alternative Energy Investment Act was taken effect. The Act will create $650 million alternative energy fund. The fund will be used to help developing the energy efficiency technology, improving the energy efficiency of existing houses and buildings and support loans, grants and rebates for energy efficiency improvements to homes and small business.

Building Codes: Pennsylvania has a state-wide mandatory residential building code based on the 2006 IECC or 2006 IRC, Chapter 11. Residential buildings can also comply with Pennsylvania's Alternative Residential Energy Provisions [2006]. Commercial buildings must also meet the 2006 IECC, with reference to ASHRAE 90.1 – 2004.

Clean Distributed Generation: Pennsylvania, in accordance with its Alternative Energy Portfolio Standards Act of 2004, adopted interconnection standards for Distributed Generation (DG), including CHP, in August 2006. The standards cover four different tiers of interconnection, up to 2MW in size. Specific technical screens and timelines are associated with each level of inter connection.

Smart Growth Policies: Pennsylvania State has two Acts to control sprawl and encourage development in core urban. The Acts called the "Growing Greener" and "Growing Smarter," were enacted in 2000.

Climate Change Roadmap for Pennsylvania: In June 2007, the Pennsylvania Environment Council released its Climate Change Roadmap for Pennsylvania. In brief, the roadmap presents a "base case" scenario reflecting current policies, Pennsylvania's GHG emissions are projected to grow in the coming years at roughly 10% per decade. However, Pennsylvania could lower and ultimately reverse this growth if it joins other states in setting goals for reducing GHG emissions, and adopting the necessary supporting policies. (88)

Pennsylvania is pursuing to take a leading position in climate change business by executing this roadmap. The agenda will help Pennsylvania in attracting new investment, industries and job that are connected with clean technology.

1.9.4. ISSUES TO BE COVERED

In sections 1.9.2 and 1.9.3, the main regulations and policies focused on consumption of gas were covered. In the next step, the regulations and policies for refinery processing and construction of utilization facilities will be covered in terms of environmental impact. Regulations and most policies for gas industry are focused in cutting down the pollutant emission such as green house gas (GHG). The reason that the natural gas is suggested as an alternative fossil fuel to replace oil and coal is for its cleanness and low pollutant emission.

1.10. CONCLUSION

The literature has revealed several issues that needs to be factored into the design, planning and implementation stages of any exploration and production activities that needs to be carried out in the Marcellus Shale. For the purposes of this project, it has revealed what we would refer to as the critical factors affecting our effort to develop an integrative model for harnessing Marcellus Shale gas reserve in a selected Pennsylvania County.

These critical factors are:

- Choice of Location
- Hydraulic Fracturing, choice and source of fracturing fluid
- Drilling Costs
- Market viability of our processed gas
- Water and waste management plan
- Environmental Health and Safety
- Regulatory Issues

CHAPTER 2: ANALYSIS FOR LOCATION

2.1. INTORDUCTION

Dr. Terry Engelder of Penn State predicts that drilling into Ohio's Marcellus shale will be more complex and costly than in New York, Pennsylvania and West Virginia. In those states, the gas is typically dry. In Ohio, the gas is more likely to be “wet,” which means it’s likely to be accompanied by petroleum or other liquids that have to be separated from the gas (89). The infrastructure required to separate the liquids increases the upfront cost of the well.

Alternatively, it has become very critical to access the Marcellus shale play in depth. It was considered that Geological, Technological, Availability of Resources, Availability of market and Demographics are most critical factors to choose a county for development operation. An ideal drilling location (county) makes maximum profit production with minimum investment. Factors that could cause or contribute to profit maximization include, but are not limited to, fluctuations in the prices of oil and gas, uncertainties inherent in estimating qualities, quantities of oil and gas reserves and projecting future rates of production and timing of development activities, competition, operating risks, acquisition risks, liquidity and capital requirements, the effects of governmental regulation, adverse changes in the market for the Company's oil and gas production, dependence upon third-party vendors, and other risks. This part of the report would target Quality and Quantity of gas in place in Marcellus shale play.

There have been drilling activities in eight Pennsylvania counties (see ***Figure 6***), Susquehanna, Lycoming, Clearfield, Indiana, Allegheny, Washington, Green and Fayette, since late 2007 or early 2008. A brief description of activities in each county would help to understand the picture. ***Table 6***, shows description of the activities in each counties.

2.2. MULTI-CRITERIA OPTIMIZATION TO SELECT THE BEST POTENTIAL COUNTY IN PENNSYLVANIA FOR GAS DRILLING

To choose the best location for drilling, we decided to systematically select one county from the 8 candidate counties in the PA, using L1 Metric and Pairwise Comparison/ Borda Count ranking methods. Twelve critical variables identified from the previous chapter were selected to rank the counties base on.

2.2.1. VARIABLES

Twelve most critical factors were chosen to decide a location where the both aspects (Quality and Quantity) can be economically maximized. These twelve factors will be assessed for all locations of interest. These twelve factors are:

1. TOC
2. CAI
3. Ro%
4. Thickness of the formation
5. Depth
6. Water availability
7. Pipeline proximity
8. Terrain condition
9. Road availability
10. Lease cost
11. Fracture porosity
12. Market distance

For an ideal location some of the factors need to be maximized (TOC, CAI, Ro% and Thickness) and the rest has to be minimized (Depth, Lease cost, and Distance from pipelines). However, a preference-hierarchy was developed for the set of factors to evaluate the potential of a location. This has been explained in detail in the later sections of this chapter. Factors which do not have quantitative values were given a ranking as per their subjectivity. Optimization analysis has been carried on these twelve factors to choose a county.

Continuous accumulations commonly cover large geographic areas. Thus, multiple assessment units are commonly defined for a particular continuous accumulation, such as the Marcellus shale, which are based on differences primarily with regard to: (90)

- Geologic facies, thickness, structure
- Hydrocarbon type
- Organic geochemistry
- Thermal maturation (oil- and gas generation windows)
- Drainage area

Organic geochemistry gains a natural attention to access a potential of a deposition. First and foremost part of organic geochemistry is Total organic carbon content of depositional system.

2.2.1.1. TOTAL ORGANIC CARBON (TOC)

Total organic content (TOC, wt %) describes the quantity of organic carbon in a rock sample and includes both the kerogen and bitumen. Geologically, TOC increases towards the maximum flooding surface; the organic matter types become more marine and therefore prone to oil/gas (91). An effort was made by USGS in 1983, to combine sequence stratigraphy and TOC from well logs, core, and cuttings to develop a model of TOC accumulation in marine source rock in Pennsylvania. ***Figure 3*** shows TOC contours over the Pennsylvania (92). By directly looking into the contours it is evident that highest TOC areas are located in South-West (Fayette County) and North-East (Susquehanna and Lycoming Counties) Pennsylvania. North-west and central part of Pennsylvania rocks has low TOC with respect to the rocks found in the two above-mentioned regions. TOC, in central and Northwest part, is sufficiently good for hydrocarbon generation. TOC contours indicate preference for Northeast and Southwest Pennsylvania. TOC values were obtained for all the eight counties. The county with the highest TOC value is the ideal one.

However, TOC is not a clear indicator of petroleum potential, for example, graphite is essentially 100% carbon but it will not generate petroleum. Further Rock-Eval analysis has S1, S2 and S3 values which can predict potential of hydrocarbon in a rock but they are not considered in this study. Alternatively, maturity index has been taken into account.

2.2.1.2. CONODONT ALTERATION INDEX (CAI)

CAI is used to estimate the maximum temperature reached by a sedimentary rock using thermal alteration of conodont fossils. Conodont in fossiliferous carbonates are prepared by dissolving the matrix with acid, since the conodont are composed of apatite and thus do not dissolve. The fossils are then compared to the index under a microscope. The CAI is commonly used by paleontologists due to its ease of measurement and the abundance of Conodont throughout marine carbonates of the Paleozoic. In order to be ascertained about the deposition in Appalachian basin, US department of the interior geological survey did research on thermal maturity of Pennsylvania deposition. CAI contours were plotted as shown in ***Figure 7***. Lower isograds that flank the CAI 5 isograds maintain the same dominant northeast trend. *In the Plateau province isograds diminish in value from CAI 4.5 to 1.5 in a northwest direction whereas in the Valley and Ridge province they diminish less dramatically in a southeast direction from CAI 4.5 to 4. The CAI 3.5 to 4.5 isograds in northwestern Pennsylvania appear to be an extension of tightly grouped isograds* (93). In all, North-Eastern Pennsylvania seems most thermally matured deposition. Susquehanna, Bradford and Wyoming seem to occupy dry and high methane content natural gas. Gas in these counties would not be carrying SO_X, NO_X, CO_2 and H_2S. So drilling in these counties won't have high gas processing cost. After removing water and heavies, the gas can be sent directly to transmission pipelines.

2.2.1.3. VITRINITE REFLECTANCE (RO %)

A measurement of the maturity of organic matter with respect to whether it has generated hydrocarbons or could be an effective source rock. The reflectivity of at least 30 individual grains of vitrinite from a rock sample is measured under a microscope. The measurement is given in units of reflectance, % Ro, with typical values ranging from 0% Ro to 3% Ro. Strictly speaking, the plant material that forms vitrinite did not occur prior to Ordovician time, although geochemists have established a scale of equivalent vitrinite reflectance for rocks older than Ordovician (94).

Ro% values are consistent with thermal maturity indices commonly used to define the "window" of oil, wet gas, and dry gas generation and preservation (95). Bradford and Susquehanna Counties (as shown in ***Figure 8***) are located in a region where dry gas is the expected hydrocarbon type (CAI 3.5; %Ro 3). These anomalous oil occurrences imply either that locally the oil escaped from being converted to gas or that oil migrated into the region after the main phase of gas generation (93). Consistent with the higher thermal maturity is the high methane content of the Natural gas. Small areas of natural gas accumulation in self-sourced Middle and Upper Devonian black shale in western Pennsylvania are characterized by CAI 1.5 to 2 isograds (%Ro <1 to 1) which correspond roughly with thermal maturity values expected for a wet thermogenic gas (refer ***Figure 7*** and ***Figure 8***). North Eastern part is expected to have less heavies (C2, C3 and C4) and condensate and hence there is no need to send it to processing plant.

2.2.1.4. FRACTURE POROSITY

Tight gas formations like the Marcellus Shale have typically low permeability. The flow of gas to the wellbore is restricted by the formation. To achieve economic production of gas the flow path to the wellbore has to be enhanced. Natural fractures created by geological processes over time can provide the necessary permeability for economic production. The permeability created is anisotropic in nature. Due to this the drainage area around the wellbore and the lateral tends to be elliptical (96). This elongated drainage area creates more production interference from adjacent wells and can leave parts of the reservoir undrained. So it becomes imperative to figure out well spacing and placement based on a deep understanding of permeability anisotropy to achieve optimum production of natural gas.

Although fracture porosity is important in economic recovery of gas it plays a lesser role as compared to other geological parameters in location selection. (refer ***Figure 9***) Fracture Porosity is important for sustained economical production as the production declines sharply. Artificial permeability has to be created regardless of the permeability of the natural fracture system. The higher the fracture porosity, the greater gas production rate will be at the start of production. However, production declines sharply and reaches a constant value over time similar to an artificially fractured formation. More importantly, the frac job, implemented in a naturally fracture formation with good fracture porosity, needs to create lesser artificial permeability.

In the Marcellus, black shales carry two regional joint sets namely, J1 and J2. J1 joints are trending in the ENE direction crosscut by NW-trending J2 joints (97). The target of horizontal drilling should be the J1 joints because they are more densely developed. This can be achieved by drilling in the NNW direction, perpendicular to the plane of bedding. Fracture pattern and subsequent permeability affect location-selection, significantly.

The fracture porosity of the Marcellus shale has been reported using shale cores from the area (98). Based on a USGS survey, the fracture porosity values were predicted for the eight counties in Pennsylvania.

2.2.1.5. LEASE COST

Lease cost involves the expense, incurred by a company to use land for exploration, drilling and production involved in oil and gas operations. As the land records date back to 1700s, the leasing process becomes complicated and may take three to six months. Land-owner, Mineral right-owner and coal mining right-owner can be three different people. In addition to Mineral right, permission is required from other two owners. It involves a complicated process of getting approval from the surface land owners to set up the equipment, needed and also the permission to drill through the coal seam. The latter is easier because it is impossible for a person with the coal mining rights to stop a company from drilling through it. Securing the lease and starting the planned activities usually take anywhere between 3 to 6 months in Pennsylvania.

Usually, Lease cost is stated per acre per year. However, this is a mutual consent between the surface land owner and the lessee. For example, when a company leases 100 acres at $750 for 5 years it means that the lease owner will get $75000 one time and the company can use its land for operation for 5 years. Lease cost for a specific location varies with the price of natural gas. Before the potential of the Marcellus as an economic play was fully understood, lease prices were at a premium of $500. When gas prices touched 15$/MMBTU, the lease cost increased to as high as $3000.

Lease cost also varies from county to county, depending mainly on the gas in place and other factors. The lease cost basically reflects the profit making of a certain area. As stated earlier lease cost mainly goes up with time. So the earlier a company gets into a play the more money it makes. Lease agreements are generally renewed at the ongoing price at that particular time. Big players have a team of lawyers and real-estate specialists to deal with leasing terms and conditions. Lease costs for each counties are easily available.

Royalty paid by the company to the lease owner is about 1/8th the total revenue the company earns from gas production (99). This is almost the same for any location in Pennsylvania. This is often the major source of revenue for a lease owner. Also along with this, some land owners ask for a tap from the pipelines on their land without paying for the gas, they use from this source. They are also paid for the pipelines that pass through their land. This cost is in addition to the lease cost and the royalty, paid to the lease owner. Sometimes companies give signing on bonuses, given as royalty starting only when production begins. ***Table 7***, shows lease costs in eight different counties in 2008.

2.2.1.6. DEPTH OF MARCELLUS

Drilling cost is strong function of the depth of the shale. Approximately, the drilling cost per foot is around $100 including pad construction, truck fleet, infrastructure development and local hiring (100). The depth of Marcellus Shale formation varies in Pennsylvania as it is slightly tilted towards the north east. As per the ***Figure 1***, if depth increases, complexity of the drilling operation increases. This affects the cost of the project. With increase in depth the pressure encountered increases and due to sequences of sands and shales the probability of encountering abnormal pressure increases.

Hence lesser the drilling depth, less problems and more money saving. While comparing selected counties in Pennsylvania, Allegheny and Susquehanna Counties are shallower than Clearfield, Indiana, Fayette and Greene Counties. In Susquehanna County, the depth of the target formation is around 5,500 feet ~ 6,500 feet.

2.2.1.7. THICKNESS OF FORMATION

Recoverable gas is strongly related to the thickness of the shale, because in shale, which is an unconventional resource, greater thickness means potentially more gas available (101). "The thickness of the shale is important, and varies throughout the area, with some of the thickest deposits are located in the Northeastern part of Pennsylvania." (102) In Pennsylvania, the thickness in Washington and Greene Counties are around 25 ~ 125 feet. However, the thickness in Lycoming and Susquehanna Counties is in excess of 150 feet. Especially, in Susquehanna County, the thickness of shale is more than 200 feet. In a report from CNX Gas Corporation and Cabot Oil & Gas Corporation, with horizontal wells, the average production rates of two regions, one located in Greene County and the other in Northwestern region, differ greatly (refer ***Table 3***). In northeastern region, the production rate (Aver. 13Mmcfe) is twice that of in Greene County (Aver. 6.5Mmcf). As a matter of fact, the thickness of Marcellus Shale of northeastern region is thicker than other counties in Pennsylvania, as shown in ***Figure 2***. This is an ideal thickness for hydraulic fracturing as the fractures can be maintained in the formation. Hence Susquehanna County possesses great prospect for natural gas production.

2.2.1.8. MARKET DEMAND

According to Dr. Terry Engelder, a geoscientist from Penn State, the gas in place in the Marcellus shale is about 500 Tcf. Today about 50 Tcf is technically recoverable and this would be a big boost to the energy sector in the U.S. Consumption in industrial sector has decreased due to economic melt-down which has led to sharp fall in natural gas prices.

Approximately 22 percent of the energy consumption of the U.S. comes from natural gas. Slightly more than half of the homes in the U.S. use natural gas as their main heating fuel. According to the American Gas Association, 5 trillion cubic feet is enough to meet the need of 5 millions household for 15 years.

Natural gas in Pennsylvania (PA) is used primarily by residential and industrial sectors. In New York (NY) the power sector uses more natural gas than the residential sector. ***Table 5***, shows the consumption of natural gas for the year 2007. PA produced only about 24 % of what it consumed in 2007 and New Jersey (NJ) did not have any production for the same year. Referring to ***Table 8***, Natural gas that consumers receive is usually processed and conditioned. Depending of the amount of processing required and cost of drilling and producing, the price of gas varies on the market. So it would advantageous to sell it where there will be maximum profit.

NY is the biggest consumer out of the three. Moreover, the city gate price for natural gas is best in New York among neighboring states (Table ***8***). It is wise to sell this gas in NY. Depending on the amount of processed gas and the market prices of natural gas, the gas processed will be sold to NY or used in PA. ***Table 9***, indicates the prices of gas in neighboring states.

The definition for City gate is a point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system.

Based on the prices given in ***Table 10***, It would be economically advantageous to sell our gas to NJ, because the price at city gate is higher compared to that of NY. But if we look at how much the gas is sold in the residential and industrial sector, it will be better to sell it to NY or even use here in PA.

There are many factors that affect the market demand for natural gas. Some of these factors affecting the demand could be weather, fuel switching, energy policy and the U.S economy.

Weather: Demand for natural gas depends highly on the time of year, and changes from season to season. Natural gas demand typically peaks during winter and tapers off during the warmest months, with a slight increase during the summer to meet the demands of electric generators. An extremely hot winter can result in even greater cooling demands, which in turn can result in increased summer demand for natural gas. Residential and commercial sectors are usually affected by the weather. In fact, according to the EIA, natural gas use is expected to increase slightly in 2009. Based on the price of natural gas for the residential sector and the number of consumers in NY it would be economic to sell gas to NY during the winter season because the price at which they receive gas in their home is higher compared to NJ and PA.

Fuel Switching: The supply and the demand in the marketplace determine the short term price for natural gas. The price of natural gas can affect the market demand. For instance, during a period of extremely high natural gas prices, in the power generation sector, they may switch from using expensive natural gas to using cheaper coal, thus decreasing the demand for natural gas.

The U.S economy is also an important factor affecting the market demand of gas particularly for industrial consumers. When the economy is prospering, output from the industrial sector generally seems to increase at a similar pace. But when the economy is in a bad shape, output from the industrial sectors drops too. These fluctuations in the industrial production along with the economy instability affect the consumption of natural gas. One example of the economy affecting the market was in 2001 when industrial natural gas fell by 6%. The total natural gas consumption this year 2009 is projected to decline by 1.8 percent because of the economic downturn.

2.2.1.9. PIPELINE AND TRANSPORTATION

Exploration and production activities are currently going on in the following Pennsylvania Counties - Lycoming, Fayette, Washington, Greene, Clearfield, Indiana, Alleghany and Susquehanna. Of all these various counties where E&P operations are underway in the Marcellus Shale, the proximity of

Susquehanna County to existing pipeline infrastructure and compressor stations gives it a competitive advantage when it comes to choosing a site for our project. Infrastructure costs are a bulk of the total price of natural gas so any minimization will result is huge cost savings.

Instead of building our own gas pipeline infrastructure to transport the natural gas, the most technical and economical means of transporting our gas to the end user is for us to connect our pipeline to the existing pipeline grid. ***Table 11*** is a pictorial representation of Columbia Gas pipeline grid which is capable of receiving and transporting gas produced from the northern part of Pennsylvania to the major markets of NY. From ***Figure 10***, it can clearly be seen that Susquehanna County has a comparative advantage over its rival counties. In terms of lateral distance to existing trunk lines, it is strategically positioned and its proximity to a major trunk line has added appeal.

Although some South-Eastern counties look like they are also close to major trunk lines, the fact that the nearest compressor station to them is quite a distance away, puts these counties at a huge disadvantage. This is compounded by the fact that the Ohio Storage Expansion Project is currently going on in the Ohio/Pennsylvania border. This will put a strain on the existing trunk lines and compressor stations in the region. Susquehanna County is free from all these problems. In addition to being relatively close to a major trunk line, it is close to three compressor stations, and most importantly it is close to New York as well as the cities around Eastern Pennsylvania where there is a present and future market for our gas. Thus in terms of economics of scale, Susquehanna County makes an excellent choice of location for our project.

2.2.2. DATA NORMALIZATION AND RANKING

After putting these 12 parameters in ***Table 12*** since the data range varies among the variables and is not the same, we need to transform the data so that they all be in a certain range, which we chose to be between 0 and 1. This process is called normalization which is discussed in the next part. In places, where actual values could not be prescribed to a certain parameter due to its inherent complexity, counties were ranked based on a scale of one to four with respect to that particular variable.

2.2.2.1. NORMALIZATION OF DATA USING THE IDEAL VALUE METHOD

Commonly, multi-criteria optimization problems involve a variety of data measured with a variety of units. Some of these categories may involve larger values, such as Depth, while other categories involve smaller figures, such as Ro%. In order to accurately compare data across a variety of categories all data needs to be scaled effectively. The Ideal Value Method for scaling entails two steps.

In the first step, the minimum or maximum value is identified for each criterion. This decision is based upon whether the problem involves the minimization or maximization of that particular criterion.

The ideal value for depth in this problem would be the lowest depth, 5500.

The ideal value for Ro% would be the highest Ro%, 2.75.

$$H_j = Max\ f_{ij}\ for\ maximizing\ a\ criteria \qquad H_{Ro\%} = Max\ f_{i\ Ro\ \%} = 2.75$$
$$L_j = Min\ f_{ij}\ for\ minimizing\ a\ criteria \qquad L_{Depth} = Min\ f_{i\ Depth} = 5500$$

The second step in Ideal Value Scaling is to equate entries in each category to that given category's ideal value. This step automatically converts all categories into maximization problems and as such identifies 1.00 as the ideal value for all categories and the lowest value in each given column as the worst alternative within that category.

$$r_{ij} = \frac{f_{ij}}{H_j}\ for\ maximization\ criteria$$
$$r_{ij} = \frac{L_j}{f_{ij}}\ for\ minimization\ criteria$$
$$Where\ r_{ij} = Scaled\ values\ of\ f_{ij}\ for\ each\ value$$

$$r_{2,Ro\%} = \frac{f_{2\ Ro\ \%}}{H_{Ro\%}} = \frac{2.25}{2.75} = 0.818$$

$$r_{2,Depth} = \frac{L_{Depth}}{f_{2\ Depth}} = \frac{5500}{7000} = 0.786$$

The normalized counties' data using the Ideal Value Method is shown in (***Table 13***) on the following page. The original data is shown in ***Table 12*** above.

2.2.2.2. L1 METRIC RANKING METHOD

The first ranking method examined was the L_1 metric method. The L_1 metric method ranks the possible counties based on their Manhattan distance from the ideal solution – the solution which combines the best possible value for each of the 12 criteria. The Manhattan distance is the sum of the twelve absolute values obtained by subtracting the county value from the ideal value for each of the twelve criteria. The shortest Manhattan distance indicates the closest county to the ideal standard, and thus will obtain the top ranking. This method does not require the distinction of criteria versus sub-criteria since it does not involve weighting. The equation for the L_1 Metric and an example calculation for Fayette County are listed below, as well as the finalized table and rankings for all counties based on the L_1 Metric, shown in ***Table 14***.

$$L_1\ Metric = \sum_{1}^{i} \left| Ideal_j - r_{ij} \right|$$

$$
\begin{aligned}
&L_1\ Metric\ (Fayette\ County)\\
&\quad = \left|Ideal_{TOC} - r_{2,TOC}\right| + \left|Ideal_{CAI} - r_{2,CAI}\right| + \left|Ideal_{Ro\%} - r_{2,Ro\%}\right|\\
&\quad + \left|Ideal_{Thickness} - r_{2,Thickness}\right| + \left|Ideal_{Depth} - r_{2,Depth}\right|\\
&\quad + \left|Ideal_{Water\ Availability} - r_{2,Water\ Availability}\right|\\
&\quad + \left|Ideal_{Pipelines\ Proximity} - r_{2,Pipelines\ Proximity}\right| + \left|Ideal_{Terrain} - r_{2,Terrain}\right|\\
&\quad + \left|Ideal_{Road} - r_{2,Road}\right| + \left|Ideal_{Lease\ Cost} - r_{2,Lease\ Cost}\right|\\
&\quad + \left|Ideal_{Fracture\ Porosity} - r_{2,Fracture\ Porosity}\right|\\
&\quad + \left|Ideal_{Market\ Distance} - r_{2,Market\ Distance}\right|
\end{aligned}
$$

$$
\begin{aligned}
&L_1\ Metric\ (Fayette\ County)\\
&\quad = |1.00 - 1.00| + |1.00 - 0.950| + |1.00 - 0.818| + |1.00 - 0.444|\\
&\quad + |1.00 - 0.786| + |1.00 - 0.333| + |1.00 - 0.333| + |1.00 - 0.333|\\
&\quad + |1.00 - 0.333| + |1.00 - 0.500| + |1.00 - 1.00| + |1.00 - 0.50|\\
&\quad + |1.00 - 0.250| = 4.752\ (Ranked\ 3rd)
\end{aligned}
$$

2.2.2.3. PAIR-WISE COMPARISON/ BORDA COUNT

The pair-wise comparison method requires that the decision maker compare each of the twelve criteria with one another to indicate preference of one criterion over another. Through an extensive pair-wise comparison which was done with the participation of the majority of the group members, 12*(12-1)/2=66 questions were asked to compare each criteria with the other 11 criteria (***Table 15***).

A preference matrix was then formulated under the following conditions:

- $i>j$ then $p_{ij}=1$ and $p_{ji}=0$
- $i<j$ then $p_{ij}=0$ and $p_{ji}=1$; where p_{ij} are the matrix entries and i & j=1-12
- $i=j$ then $p_{ij}=p_{ji}=1$

Each row in the matrix was summed and the total of all "Row Sum" for each criterion was also calculated. This value is a representative of importance of each criterion. The higher this value the more important the criterion. Then, the Borda Count method was used to determine the weight for each criterion. This was done simply by dividing each row sum by the total of the row sums to get the portion of important of each criterion comparing to the rest (***Table 16***).

Finally to calculate the rank of each county we multiplied the last column of ***Table 16*** by the whole ***Table 13*** (i.e. a 12×8 matrix containing normalized values for each criterion for each county). The Second row of ***Table 17*** contains the result of this multiplication, which is basically the rank of each county with respect to the 12 criteria as well as weight of each of them.

The rankings, derived from both methods were almost the same. Susquehanna County was ranked first in both. Moreover, using L_1 Metric, Allegheny County was ranked 4^{th} whereas, with Pair-wise comparison method it was ranked 6. Basically that was the only change, which also influenced the ranking of two other counties, Clearfield and Indiana (***Table 18***).

2.3. CONCLUSION

As discussed in the introduction, Geological, Technological, Availability of Resources, Availability of market and Demographics were accessed for eight counties in Pennsylvania. Values were collected for each parameter for all eight counties. Optimization methods (Borda Count and L1 Metrics) were applied to this selection criterion. Table 7 suggests that Susquehanna County come out as Rank one. In other words the characteristics of the Susquehanna County are near to Ideal solution.

It was decided that the production plan will be developed for the Susquehanna County. Drilling, Infrastructure development (Pipeline, Gas Gathering and Gas Processing) and Production activities would be designed for Susquehanna County. Regulation and Policy would be reviewed with the perspective of Susquehanna. A Marcellus shale development plan has been designed in the later sections of this report.

CHAPTER 3: ENGINEERING DESIGN

3.1. INTRODUCTION

This part of the report will be focused on developing a sustainable project plan for Susquehanna county exploration and production of natural gas. This will be including project activity carried out throughout the project life. Each of the activity is justified (in separate sections) and an effort is made to design this problem with real time field data. Data used in these sections came from reports, presentations, telephone communications, email exchanges or personal interviews. Marcellus shale is in its nascent stage of development unlike its more illustrious southern play the Barnett, and hence there is not enough data available for the play. Moreover it was very difficult to access the propriety data of companies drilling in Marcellus shale. It was concluded that detailed and accurate calculations are beyond the scope of this project. Since a detailed economic analysis of Drilling, gas production, processing and transportation involves too many parameters, it is not possible to consider every one of them. For the purpose of brevity, some general assumptions have been made and only the most important factors (with integrated cost) have been considered.

3.2. ASSUMPTIONS

- **Discount rate**: Related to historical lending rates of long term senior debt facilities – a figure of 15% was used.
- **Inflation**: Average of 0% was used for analysis.
- **Project duration**: Twenty years in accordance with the minimum lifetime of significant results.
- **Revenue**: Single source of revenue is gas sales at a rate not exceeding the EIA projected price.
- **Investment**: Drilling/Fracturing activities has been outsourced to service companies. Required gas processing plant and gas transmission plant would need initial investment. All capital expenditure is required for reliable long term gas production.
- **Costs**: For the sake of simplicity, Operating cost (including the capital cost) has been used for NPV calculation. This cost includes operational expenses (mainly contractually determined long term operation and maintenance, labor and finance costs). However, major part of activities does not have further break-up for costs.

3.3. DETAIL OF PHYSICAL LOCATION

Due to the lack of real seismic data placement of the wells is not possible. The Marcellus Shale extends through all of Susquehanna County, Pennsylvania. The TOC contour maps are not very specific in Susquehanna. Based on size of other sweet spots in Devonian shale plays across the US an educated guess was made. The size of a sweet spot was estimated at about 10,000 acres each. 90% of this area will be drilled for natural gas. Susquehanna has a total land area of about 500,000 acres. It was decided to lease 10% of the land which would translate into 5 blocks of 10,000 acres each. These 5 blocks would serve as the reservoir sweet spots.

3.4. RETURN ON INVESTMENT

The project may face a barrier to implementation due to the fluctuating market gas prices. To illustrate this, an investment analysis in which we compare the Internal Rate of Return (IRR) of the proposed project activity to an industry benchmark. Sensitivity analysis has been done for calibrating the effect of price fluctuation.

3.5. DESCRIPTION AND PURPOSE OF THE PROJECT ACTIVITY

The main objective of the project is to extract the unconventional gas from Marcellus play and contribute to the sustainability of energy requirement in Northeastern US. The project would deliver gas in a capacity (peak) of 500 Mmcf per day. The project will be connected to the local grid via an on-site compressor stations. The local grid is part of the Columbia gas pipeline network, which serves the natural gas requirements in NY, NJ and PA.

The project will sequester an estimated amount of approximately 960,000 tons CO_2 in five years of drilling operation. The project contributes to local economic development and the project partially fulfils the energy-independence of US. The project fits with the Policy and Regulation of PA.

This project will involve following activities during its entire life.

- Drilling/completion,
- Construction of gas processing and conditioning plant
- Building Pipelines

3.5.1. DRILLING

Horizontal drilling was considered better for Susquehanna as it has following advantage associated with it:

1) Most oil and gas reservoirs are much more extensive in their horizontal dimensions (thin reservoir) than in their vertical dimension. So, if vertical drilling were used, small amount of gas would be extracted from a small area just surrounding the wellbore. However, horizontal wells could reach these flat reservoirs. (30) The Marcellus Shale extends from Ohio and West Virginia northeast into Pennsylvania and southern New York. (***Figure 1***) It is almost 7,000 feet deep or more below the surface in the Delaware River Valley which is located in Pennsylvania. (31)

2) A horizontal well can better exploit the shale in case of the presence of a vertical natural fracture system. (30) The Marcellus Shale is heavily jointed by cross cutting vertical natural fractures. So, a vertical drilling would be expected to intersect not more than two fractures at a given location. However, a horizontal one, drilled perpendicular to the bedding plane in a direction such that it will intersect maximum number of fractures will result in a maximum drainage area. (22) Hydraulic fracturing is usually used to raise the gas recovery, but it is expensive (Hydraulic fracturing can account for as much as 50% of total well costs (103)) and is hard to complete. So, if the shale has enough natural vertical fracturing and the well is drilled horizontally, hydraulic fracturing would not be needed.

3) As the shale has low permeability and porosity employing a vertical will result in an low and uneconomical production rate. However, employing a horizontal well in this low permeability and porosity shale in tandem with hydraulic fracturing would raise production rate and making it economically feasible. The permeability and porosity of Marcellus Shale is low like other gas shale plays. Porosity of Marcellus is around 9% (104) and permeability is around 1md ~ 20md. In accordance with the geological parameters of the Marcellus Shale, drilling horizontal wells with hydraulic fracturing with about 3,500~4,500 ft-long lateral would be best. (105).

3.5.1.1. DRILLING FLUID FOR MARCELLUS SHALE

As mentioned in literature review, drilling fluid is an important element for a successful drilling operation. The Marcellus shale in Pennsylvania is deeper than in the neighboring areas. (22) It means that the reservoir pressure is generally higher than other area. Air is often used as a drilling fluid (106), but it is unacceptable when excessive pressure is encountered. Also, air is cheaper than conventional mud or other water based drilling fluids. A typical horizontal well in the Marcellus will require, around 3 to 5 million gallons of water for hydraulic fracturing indicating a lot of water is already being used. Air and water both are good for drilling in Marcellus. No complex chemical drilling fluids are required for drilling in Marcellus shale.

Air–based fluid and water-based both have been used for the regions with depth up to 6,000 ft.

Generally, air-fluid is used up to the depth of 2,500 ~ 3,000 because it works fine in low strata pressure and it is cheap. Sometimes, air fluid drilling extends to kick-off point (around 5,000 feet. However, if the well started getting wet, water-based fluid would be used earlier. As drilling depth increases, the pressure of the overlying strata increases and hence a fluid is required which can balance the pressure gradient at that depth. Water based drilling with additives suits well in these conditions therefore it is used in higher depths. (107) Additives are used in water based drilling to increase the density of the fluid so that it can sustain formation pressure efficiently. Typically, air fluids do not contain additives, as the solution is heterogeneous. (31) Moreover, low permeability of formation allows the use of air. One more advantage associates with air is that it minimizes the formation damage. The amount of additives is around 1% ~5% of drilling fluid (108). Below ***Table 19*** shows the additives for drilling operation in Marcellus. While hydraulic fracturing operation, various additives would be used (79). After drilling operation, these chemicals are treated before discharging them.

In Susquehanna County, the depth is around 6,000 ft and the pressure is lower than other reference shale such as Barnett Shale, Fayetteville and Haynesville Shale (109). Literature suggests that, the air-drilling is good till the depth of 6,500 ft. According to experience in other shale where the reservoir pressures are higher than Marcellus Shale, air drilling was found successful till this depth (106). This discussion leads to the conclusion that air-foam drilling fluid should be used as a main drilling fluid, and occasionally, water-based fluid would be used where high pressure/wet area is encountered. Amount of water used in drilling operation is not a critical issue for engineering design.

3.5.1.2. COMPLETION STRATEGY

A typical casing program will have a conductor casing to a depth of 400 ft, a surface casing to a depth of 4000 ft, an intermediate casing to a depth of 13000 ft and the production casing to a depth of 20000 ft. As for a well in the Marcellus formation in Susquehanna County, the total depth needed to be drilled is about 6000 ft. Due to this reason we will run only the three casings namely, the conductor casing, the surface casing and the production casing.

Conductor casing: The conductor casing is the first string in the hole. The conductor casing is needed to circulate the drilling fluid to the shale shaker without eroding the unconsolidated surface sediments below the drill rig when the drilling is initiated. It also protects the subsequent casing strings from corrosion and maybe used to provide structural support for a portion of the well head load such as a BOP (blow-out preventer).

Surface casing: The surface casing is in place to prevent cave-in of weak near-surface sediments and also protects the underground freshwater from the various drilling and completion as well as production activities. It also supports the various strings below and protects from corrosion. The surface and conductor casing are required by law due to their implications for safety and the environment.

Production casing: **T**his runs from the surface to the total depth of the well. In this particular case it will also extend to the lateral portion of the well. It provides a stable production interval and allows for ease of reentry. Production casing is perforated at the production interval.

Horizontal Section: The main aim of the lateral section of the well is to maximize reservoir contact. By casing the lateral we will actually be reducing the reservoir contact. The main reason behind casing the lateral is to prevent well bore collapse. The pumping pressure to induce the fractures is about 7500 psi. At this pressure, if the well is not cased it would collapse. Perforations along the lateral will provide the channels for flow of gas to the well bore.

Production Tubing Size: The size of the production tubing selected depends on the depth and fluid being produced. For a high pressured gas well in the Marcellus drilled to a depth of 6000 ft the ideal casing size is 5”. The corresponding bit size for a hole of that size is 7”. These values are estimated based on graphs of other regions. The pressure gradients in the locations shown in the (***Figure 12***) are similar to pressure gradients in the Marcellus and so this figure can be used. Gradient in the Marcellus is between 0.3 to 0.58 psi/ft while the gradient in West Texas is 0.433 psi/ft and that in the Gulf Coast is 0.465 psi/ft. Also due to the low permeability we can select a smaller bit size for a 5” casing string. Liner of 2” will be fitted inside the production casing as the production tubing. Based on the size of the production tubing the surface and conductor casing sizes can be decided. Refer appendix for detailed design.

Setting Depths and Sizes of Conductor and Surface Casings: The conductor casing is set to a depth of 300 ft. Its diameter is 30” and hole size is 36”. The conductor casing on the other hand is 13” in diameter and hole size is 17”. It is set to a depth of 3000 ft. (Refer ***Figure 13***)

Cementing of the casing: The casing has to be cemented into place after the casing is run into the hole. Cementing is performed for the following reasons:

- Provide bond and support for the casing.
- Restrict fluid movement between formation and surface through the annulus.
- Prevent Pollution of freshwater formations.
- Prevent casing corrosion.
- Stop the movement of fluid into fractured formations.

API Class A cement was chosen for the completion of the wells, since it passes all the criteria. API Class A cement has Ordinary sulfate resistance, it can be used for Well Depth of 6000 ft, Temperature up to 170 °F and finally it requires 5.2 gallons of water per sack of cement (one sack= 94 lb).

3.5.1.3. HYDRAULIC FRACTURING

Hydraulic fracturing is an operation performed to increase the permeability of a reservoir artificially by injecting fluids under high pressure to create fractures in the rock. A typical well in the Marcellus is using stimulated by pumping slickwater. A typical hydraulic fracture design will have the following parameters. (***Figure 14***)

- Stress orientation North 45° East
- Fracture gradient is 0.93 psi/ft
- 10 stages
- 4 to 5 clusters per stage
- Cluster spacing 25 feet
- Length of lateral 4000 feet
- Injection pressure is 7500 psi
- Water required is 102,500 bbl (10,250 bbl per stage)
- Bulk flow rate is 100 bph
- Rate per cluster 20 bpm
- Flow back is 30%
- Proppant used Ottawa white sand 5,000,000 lbs
- Proppant used per stage 500000 lbs
- Sand size used is 50% (40-70 mesh) and 50% (100 mesh)
- Proppant used per foot of lateral is 1300 lbs

These parameters are fixed based on experience from other plays and also on local development. Although the Marcellus has not been in development from a long time, best practices will eventually be development locally entirely. This data was provided by John Reinhart of Chesapeake and Bill Ottaviani of Rex Energy . See appendix for design.

Stimulation Method: To achieve effective stimulation we need to use a technology widely used in for hydraulic fracturing for enhanced gas production. The two technologies which will be used are key to the success of the frac job are "Just-in-Time Perforating" and "Annular Coiled Tubing Fracturing". For the gas wells we will be using "Annular Coiled Tubing Fracturing" so as to minimize the problems caused by loss of balls and their recovery from the wellbore. This gives rise to the number of stages used for a frac job. (***Figure 15***,***Figure 16***)

3.5.1.4. PRODUCTION DEVELOPMENT PLAN FOR SUSQUEHANNA COUNTY

3.5.1.4.1. NUMBER OF WELLS

According to ***Table 1***, land usage for horizontal well is variable from 160 to 640 acres. Land required for one horizontal well shrinks with the technological advancements. Typical, multiple horizontal well from a single drilling pad drains from 200~640 acres (110). Apparently, a horizontal well with single branch must be using a area smaller than the area for multiple branching. (***Figure 17***), from the book "Horizontal well technology" (111) shows the typical land usage of vertical and horizontal well. ***Figure 17*** shows a 3000-ft-long horizontal well approximately drains 150 acres. According to a Tom Lopus presentation from Quest Eastern Resources, recent studies have shown that a single 3500 ~ 4500 ft-long branch horizontal well will drain around 130 ~ 150 acres.

3.5.1.4.2. LAND USAGE

Susquehanna County, single branch horizontal wells with 4000 ft-long (In Marcellus shale, typically, 4000 ft-long lateral horizontal wells are used. (105)) will be made. This 4000-ft-long horizontal well will require an area of 150 acres. However, the land usage depends on the strata condition at given point of drilling which is tough to include in this study. For the sake of convenience, average values are used for land usage. The number of total wells will be decided according to total lease area in particular part of Susquehanna County.

3.5.1.4.3. PRODUCTION RATE

According to the ***Table 3***, production rate from a horizontal well is changes with region and also with the horizontal well length in the Marcellus. To decide the production rate in Susquehanna County, it can be assumed that the average production rate of first year is 6.5 Mmcf per day. From a presentation from John Reinhart of Chesapeake (105), average production rate of horizontal well in Marcellus can be estimated to reduce around 80% at the end of the fifth year and it to be expected to remain constant for another 20 to 30 years and in some specific cases up to 60 years. From this it is possible to estimate the natural gas production from a single horizontal well after 20 years. ***Figure 18*** shows the typical production rate graph of Barnett Shale.

According to this ***Figure 19***, the production rate for certain period of single well will be calculated approximately. Actually, very first production rates in Susquehanna County, are significantly high and variable. Usually, to make a horizontal well in Marcellus, it takes 30~45 days (112). However, it includes multilateral horizontal well. In this project, to make a 4000 ft-long lateral horizontal well, assume that it takes 1 month. In Susquehanna County, the Cabot reports that the maximum initial production rate of a horizontal well is 8.8 Mmcf/day (113). In addition, in northeastern area or Pennsylvania, a horizontal well made by Cabot Oil and Gas Corporation, produced 13 Mmcf/day initially. And a report by Range Resources, the initial production rate in northeastern region is 24.5 Mmcf/day (113). The average production rate by reports from Chesapeake, Range and Cabot, is around over 6 Mmcf from horizontal well. These rates are 2 or 3 times bigger than they estimate at first time (114). So, production rate of wells will follow above Graph1. Below ***Table 20*** shows the total production rates of companies which are producing natural gas in Marcellus Shale in certain period.

(***Table 3***) shows a single well production rate which are made in each month for 5 years. Assume that there is no failure to produce the gas from each well. However, failures are the integrative part of a design problem and they may occur at each step of operation. For example, rigging tools may face mechanical or electronic problem while drilling. Failures like fire, explosion, blowout, pipe failure, casing collapse, unusual or unexpected formation pressure, environmental hazards can be encountered at any well (115). An assumption 'these small accidents are occurred occasionally and the operators usually fix those problems' has been made to make the analysis simpler. Therefore, it can be concluded that no failure stops the operation of making the horizontal wells and to produce the gas. ***Table 21*** and ***Table 22*** shows total production of 300 wells for 20 years, and the daily average of production rate was calculated by year. Costs for drilling and completion of a horizontal well are shown in ***Table 4***. Data has been collected from correspondence with companies and Professors working in this field.

3.5.1.5. COST FOR COMPLETING A WELL

In Susquehanna County, the depth is 5,500 ~ 6,500 feet with 4000 ft-long lateral length. The average cost for making a horizontal well is 3.5 million ~ 4.0 million. This single well cost includes rigs leasing cost which is around $22,000 per day (105). Also, this cost includes pad construction, water truck traffic, infrastructure building, gas pipelines and local hiring (114). It should be noted at this point that this cost does not contain the cost of leasing land in Susquehanna County.

Completing a well is a very expensive process. This cost is different from one company to another. Generally, a vertical well in Marcellus costs around $810,000, whereas a horizontal one costs approximately 3-5 million dollars (116). According to ***Table 4***, one can estimate the cost range of completing wells in Marcellus Shale. There is a report from Range Resources who has performed a lot of drilling operation in PA. The average cost of making horizontal wells in 10 years in Susquehanna County is $4.0 million.

3.5.1.6. SUMMARY OF DRILLING ACTIVITIES

Sixty wells per year will be completed in five different regions (10,000 acre each) in Susquehanna County using 5 rigs. As per the decision made in design part, only one rig will be used employed in a region (occupying 10,000 acre). Installation of one rig in one region avoids the chances of vibration (by constructive interference) and collapse of bore holes. Considering the fact that the infrastructure cost (Pipeline and Gas processing station) is significant, it was decided to produce at a lower rate, which can be achieved by drilling in alternative years. In other words, there will be no drilling activities in even number of year till the end of 10^{th} year. In a matter of ten years, total 300 horizontal wells will be made in Susquehanna County. Total land usage, production rate and cost are shown in *Table 23*.

Lease cost can be minimized by leasing the whole land (50,000 acre) at once and hence it is planned to occupy the five regions at a time before starting drilling operation. ***Table 24*** shows the projected production rate for this project in twenty consecutive years. And accumulative production rate are shown in ***Figure 20***. It is assumed that there are no dry wells and production rate is estimated mathematically. ***Table 25*** shows the total cost of drilling and completion of horizontal wells. To make the analysis simpler, assumptions has been made wherever required. Average and estimated values are used for quick results.

3.5.2. WATER

3.5.2.1. WATER AVAILABILITY

Pennsylvania has three times the water available comparing to Texas, where 10,000 of similar gas wells have been drilled in Barnett shale. Susquehanna County is located in Susquehanna River basin, which encompasses 20,960 square miles, or 46 percent of the state. More than 75% of the basin lies in Pennsylvania (***Table 26*** and ***Figure 21***) Susquehanna River is one of the largest rivers on the eastern coast. It is one of the most important water sources to millions of people (117). Susquehanna River Basin has 6 sub basins, two of which, Middle Susquehanna and Upper Susquehanna Sub basins encompass Susquehanna county (***Figure 23*** *and* ***Figure 23***).

Despite western Pennsylvania, where there is no control over water withdrawal from water sources and gas driller companies have "pumped dry" some of the streams, i.e. Sugarcamp Run in Independence Township, Washington County and Cross Creek in Hopewell Township, Washington County, according to DEP investigators, eastern and central Pennsylvania have strict regulations and policies regarding water withdrawal and consumption. Basically, no driller can withdraw and consume great amount of water without permission from the river basin commissions, i.e. SRBC or DRBC. In our case SRBC plays a big rule in the success and speed of gas drilling and fracturing process. Here we discuss the most important steps need to be taken to acquire permission from SRBC for water withdrawal and consumption.

3.5.2.2. POLICIES, REGULATIONS AND PERMISSIONS ON WATER USAGE

There are several clear and strict regulations regarding water consumption in Susquehanna River Basin. In this part two inevitable and primary SRBC water use regulations and their respective threshold quantities will be discussed.

3.5.2.2.1. CONSUMPTIVE WATER USE DEFINITION (§806.3)

The loss of water transferred through a manmade conveyance system or any integral part thereof (including such water that is purveyed through a public water supply system), due to transpiration by vegetation, incorporation into products during their manufacture, evaporation, <u>injection of water or wastewater into a subsurface formation from which it would not reasonably be available for future use in the basin</u>, diversion from the basin, or other process by which the water is not returned to the waters of the basin undiminished in quantity (118). It is necessary to mention that since, in the hydraulic fracturing process, water is injected below the level of freshwater aquifers, it is not considered as "a return to the waters of the basin" (118).

Any water consumption exceeding 20,000 gpd/30-day average (600,000 gallons) of water from any source, including users on public water supplies requires approval from SRBC. The project sponsor must apply for Consumptive Water Use, for which application form SRBC #24C needs to be filled out. This application requires exact information from the project sponsor some of which are, description of the company or facility, Location of the facility, “water source(s)” from which water is consumed, amount of water required, the method by which this amount was calculated, a flow chart showing how water is moved to the facility, “including location and amount of any losses” , and finally a Consumptive Use Compensation Option, which can be Discontinuing consumptive water use, Reimbursing Commission for water storage, Providing water storage, or any other acceptable option which needs to be explained. This form associated with the appropriate application fee needs to be submitted to the SRBC office in Harrisburg.

3.5.2.2.2. WATER WITHDRAWALS (§806.4)

SRBC limits water withdrawal from surface water, groundwater, or a combination of the two to 100,000 gpd/30-day average (3,000,000 gallons). Any further water withdrawal beyond this limit requires permission from SRBC. The permission can be obtained by applying for Surface Water Withdrawal, for which form SRBC#24S need to be filled out and submitted to the head office of SRBC in Harrisburg. As the requirements of this application, we need to specify the “location of the proposed source” and any “alternative sources”, from which water will be withdrawn, purpose of withdrawal, which, in our case, is hydraulic fracturing, the amount of water to be withdrawn, history of any previous state or federal permit(s) issued, the calculation supporting the amount of water needed, “existing and projected total water use”, existing water sources, which can be water wells, stream intakes, reservoir , springs, etc and finally any existing or proposed “raw water ponds, lakes, intake dams, and storage dams”.

3.5.2.2.3. APPLICATION FEES

Each application has a fee associated with it. It can be derived from the Fee Resolution 98-19 from SRBC website and is to be submitted at the application submission time. This fee must be paid in advance and is a non-refundable fee. No amount of this fee will be credited to the project sponsor even if the approved quantity of water is less than what the project sponsor requested and paid for. However if any single application fee exceeds $10,000, the project sponsor has the option to pay it in installments. The fee can be paid in three equal annual installments, with the interest of 10% per annum on the unpaid balance. The first installment is due at the time of application submission.

3.5.2.3. WATER CONSUMPTION

Each well requires 3 million gallons of water for the fracturing process, which is executed in two days. With the assumption of using equal amount of water in each day, we are going to use 1.5 million gallons of water in one day. Also having considered drilling 5 wells per month, 15 million gallons of water each month will be required. Since we can only withdraw up to 3 million gallons of water per month without requiring Water Withdrawal Approval from SRBC, we either need to apply for Water Withdrawal Approval to withdraw more water or get water from a water supplier company. In either case, we need to apply for Consumptive Water Use, since we are exceeding the limit of consuming 600,000 gallons of water per month.

No Drilling activity can start without the drilling permit, for which we require to have the approvals from SRBC, meaning no drilling without Consumption Water Use approval and Water Withdrawal approval from SRBC. This process needs to be done a few months before drilling starts, since SRBC meets only quarterly to review these applications.

3.5.2.4. WATER STORAGE

Water storage is an option to save water for the seasons that the stream flows are low and SRBC does not allow water withdrawal in great magnitude. Basically, based on the stream slow statistics from U.S. Geological Survey (USGS) drillers can withdraw water in February, March, April and sometimes May and store it in either steel tanks or a water storage pond, depending on the limitation of the site condition. Each of these options has advantages and disadvantages. Water storage pond which is basically a very large lined pit, usually requires a large flat area, which can most likely be found in rural areas. Having such a pond on site, drillers not only can store water withdrawn from water sources, they can also benefit from precipitation too. Water ponds disturb the land for a long period of time, not to mention that large amount of water evaporates from them in warm days. Pond evaporation needs to be calculated based on ***Table 27***, which was prepared by The Pennsylvania State University, and submitted associated with Consumptive Use application.

3.5.3. WASTEWATER TREATMENT

USEPA does not regulate most hydraulic fracturing under the Underground Injection Control (UIC) provisions of the Safe Drinking Water Act (SDWA) because it considers this, an activity "associated with production wells [for oil and gas] and not covered by the UIC Program or the SDWA. Head of DEP admitted in a recent hearing in Pittsburgh that treating the contaminant fracwater is another problem.

Drillers are taking their fracwater to municipal wastewater treatment plants; however because of the high level of dissolved solids (heavy metals and salt) those plants cannot treat the wastewater properly, since they do not have the adequate industrial wastewater treatment facilities. After a test, resulted higher-than-expected level of total dissolved solid in the Monongahela, the DEP warned municipal sewage plants to get state approval before accepting gas well wastewater. Basically, frac water needs to be treated at specialized wastewater treatment plants, which can take heavy metal and salt out of fracwater. Unfortunately not many (less than 10) of these plants exist in the Pennsylvania. This shortage in wastewater facility treatment plant has created a big challenge to drillers and authorities. Some drillers have started to recycle and reuse the fracwater onsite and send it for treatment after multiple usages. In addition, the SRBC is working with industry personnel to determine best management practices for hydrofracing water reuse. Also with a contact, made with DEP office in Harrisburg, we were told that there is a very significant interest in building these treatment plants, due to this wave.

3.5.4. DRILLING PERMIT

After acquiring approvals from SRBC, we can submit the drilling permit application, which was discussed in the literature review. This application has also a fee associated with it. Prior to February 2009 it was only $100 per well regardless of the specification of the well, however since then it has changed and now it is calculated based on the depth and length of the well. In this project with D=6000 ft and L= 4000 ft the application fee was calculated to be $2150. (Appendix C-1)

3.5.5. RECLAMATION

To avoid any footprint in the land, the gas company is obligated to reclaim the land. Especially if the company had used a water storage pond on the site, they need to take care of the sediments and appropriately recover the land with the top soil on top ready for vegetation. All the wells also need to appropriately be plugged according to section 210 of Chapter 11(Oil and Gas Act) of the Pennsylvania Code.

"To ensure that the operator will adequately perform the drilling operations, address any water supply problems the drilling activity may cause, reclaim the well site, and properly plug the well upon abandonment. The bond amount for a single well is $2,500; a blanket bond to cover any number of wells is $25,000." (117)

3.5.6. GAS PROCESSING

The installation of even rudimentary natural gas collection systems would involve expenses for the operator. Unfortunately, there is no processing plant in N-E Pennsylvania. In depth study of the Marcellus gas obtained in NE Pennsylvania does not contains heavies and hence building a processing plant is not a plausible alternative. However, water can be separated at gathering stations. But this is required for water separation. As the concentration of heavies is very low there is no further processing is required. Financial analysis is carried out, Given that the main potential financial returns derived from the sale of gas. the feasibility of this project is, thus, dependent on factors related to energy sector and *to the cost of lease/infrastructure.*

3.5.6.1. CONSTRUCTION OF GAS PROCESSING/CONDITIONING PLANT

According to Randy Nikerson vice-president of Markwest (A Natural gas processor) company in the Appalachian, there is no market for ethane or propane in Northeast, Pennsylvania and hence there is no incentive to separate the ethane from natural gas. Moreover, ethane has higher calorific value and this increases the calorific content of natural gas. High calorific content gas pays better price in the market. As per Rex Energy and Markwest, Natural gas form Marcellus shale doesn't contain acid gases and heavier hydrocarbons. Based on varied assertions, it was concluded that the Marcellus gas in this region contains mostly methane (98%), ethane (2%) and water vapor. Processing of this has been discussed in following paragraphs.

The installation of even rudimentary natural gas collection systems would involve expenses for the operator. Unfortunately, there is no processing plant in Northeastern Pennsylvania. In depth study of the Marcellus gas obtained in NE Pennsylvania does not contains heavies and hence building a processing plant is not a plausible alternative. However, water can be separated at gathering stations.

Water removal: Natural gas produced always contains water vapors which can lead to corrosion and reduction in calorific value of gas. Water is removed from the gas stream because it can form hydrate which may block valves and pipelines. To handle this natural gas processing and conditioning plants have gas dehydration processes used to remove water. To sell gas to the consumers, it has to meet certain specifications. The usual pipeline specification for water content is between 4 to 7 pound of water per million standard cubic feet (lb/MMSCF) or 64 to 112mg/m^3. There can be formation of hydrates while transmitting natural gas with water content. Hydrate formation may block the pipelines and valves. Removal of water prevents these formations. Moreover, water can cause corrosion in the pipeline when the gas contains acid components.

Water content determination: One way to determine water content is to use (***Figure 24***), which gives a pressure and temperature correlations and (***Figure 25***) provide corrections for gas gravity. (See Appendix) these charts are used in industry and give good results for sweet gas (because doesn't contain acid gases such as H_2S and CO_2). As mentioned earlier gas from the Marcellus shale is mostly free from acid gases and contains less amount of heavier ends. It was assumed that natural gas composition from Susquehanna containing over 98% methane and small amounts of 2% ethane. It is desirable to calculate the water content of this gas at 800 Psi and 100 ^{o}F (38 ^{o}C). The water content of this gas is about 69lb/MMscf or 1105mg/m^3 which is way beyond the specification limit (64 mg/m^3) thus needed to be removed.

Water removal process: Natural gas processing can be accomplished at or near the wellhead and is usually known as field processing. In this study the water removal is accomplished at the wellhead. There are different ways of removing water from the gas. The most commonly processes used are dehydration by absorption or glycol dehydration. Dehydration by absorption uses liquid desiccants while dehydration by adsorption uses solids desiccants. Liquid desiccants dehydration are chosen over solid desiccants because, they usually have an appreciably lower cost of installation and operation than a solid desiccant system for the same volume of gas. However solid desiccants will reduce the water content of the gas more that liquid desiccants. Based on these facts removal of water by liquids desiccants is the optimal method of dehydration.

In dehydration by absorption, liquids such as methanol and glycols possess the ability to absorb water from the gas. But to be very effective, the liquid should possess the following properties (119):

- High absorption efficiency.
- Easy and economic regeneration.

- Non-corrosive and non-toxic.
- No operational problems when used in high concentrations.
- A good thermal stability to prevent decomposition during regeneration
- No interaction with the hydrocarbon portion of the gas, and no contamination by acid gases.

Glycols have proved to be one of the most effective liquid desiccants in current use because they fulfill most of the properties described earlier. They are good desiccants because they have enough oxygen atoms to provide numerous sites for moisture absorption and retention by hydrogen bonding (120). In addition they have low vapor pressure (glycol is not added inadvertently into the gas stream while removing the moisture), low solubility and high boiling point that reduce glycol losses during regeneration.

H-O-H H-O-H

$HOCH_2CH_2$-O-CH_2CH_2-O-CH_2CH_2OH

Schematic diagram for Hydrogen bonding of water on triethylene glycol.

The four types of glycol that have been successfully used to dehydrate natural gas are ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (T4EG). Factors that influence the selection of the particular glycol for a specific application include (119):

- Comparative cost of the glycols
- Freezing point of the glycol/water solutions
- Viscosities of the glycol water mixtures and the process fluids as well
- Solubility of the glycol in the hydrocarbon process fluids, and
- Temperature of operation.

The heaviest glycol (TEG and T_4EG) are the ones that have a strong affinity with water, but TEG has gained nearly universal acceptance as the most cost effective glycols due to superior dew point depression, operating cost, and operation reliability (119). Structure of the TEG(below) is helpful for better understanding.

CH2-O-CH2-CH2-OH CH2-O-CH2-CH2-OH

A detailed list of assumption and results is in Appendix C1.

3.5.6.2. PLANT DESIGN

Contractor: The contactor should be kept at 100 ^{o}F(38 ^{o}C), 800 psi(5.52 Mpa) pressure to avoid the Vaporization losses and hydrate formation. The number of trays in the contactor is 12 for maximum removal of water at 64mg/m3 and the diameter was assumed to be 3.6m and the height 8.6m based on simulation software.

Reboiler: The reboiler is operated at 400°F with TEG and at atmospheric pressure. At lower pressures the gas can absorb more water per unit volume. It is difficult to get the required TEG purity if running at lower temperatures while higher temperature will cause the degradation of glycol. The temperature at which TEG start to decompose is of 464°F (240°C). Higher reboiler temperatures yield leaner glycol. At a 400°F (204°C), the typical maximum regeneration temperature, TEG yields a lean-glycol concentration of 98.6 wt% (121).

The reboiler duty calculated was equaled to 2.74 MJ/h. Appendix C

The rich glycol preheater duty is 1878 MJ/hr.

Glycol /glycol exchanger: The heat for the glycol/glycol exchanger is 2079 MJ/hr.

Gas /glycol exchanger: The heat for the gas/glycol exchanger is -801 MJ/hr.

Pump: An electric pump is preferred to a gas assisted pump. With an electric pump it is possible to reduce CH_4 losses and emissions. Assuming a pump with a power rating of 3 horsepower, it will cost about $1370 and would require approximately 3kW to operate.

Flash tank: The main purpose of a flash tank is to remove dissolved gas from the rich glycol stream and improve the glycol reconcentration process. It also helps to reduce methane emission and other hydrocarbons emissions. The normal operating pressure and temperature ranges from 50 to 75 psig (446 to 618 kPa) and 150°F (66°C).

Still a column temperature of 225 ^{o}F is ideal because at T> 250 there are losses of glycol due to excessive vaporization. If temperature is too low, too much water can be condensed and this will increase the reboiler heat load. The still column is mounted above the reboiler and the bottom still column is packed with a 25-mm pall ring. The diameter for the still column was 736 mm. (***Figure 26***)

The wet gas passes through an inlet scrubber to remove solids and free liquids, and then enters the bottom of the glycol contactor. Gas flows upward in the contactor, while lean dry glycol solution flows down over the trays of an absorber tower where water vapor is absorbed in the glycol thus depressing the water dew point. Rich glycol absorbs water and leaves at the bottom of the column while dry gas exits at the top. The rich glycol flows through a heat exchanger at the top of the still column where it is heated and boiling off the water vapor and the continues to the flash tank where dissolved gas is removed. The rich glycol from the flash tank is further heated by heat exchange with the still column bottoms, and then becomes the feed to the still. The still produces water at the top and a lean glycol at the bottom that is pumped back to the absorber. As the glycol fall from tray to tray, it becomes richer and richer in water. And gas as it raises to the top of the contactor it becomes leaner and leaner in water vapor.

3.5.6.3. COST INCURRED FOR GAS PROCESSING

A capital cost of a new TEG dehydration plant is about 6.5 MM$ based on these assumptions (121):

- Use of TEG
- Having BTEX containment equipment
- Operating pressure of 600 to 800 psig

A dehydration plant is required to be built in Susquehanna for the processing of 400MMscf of natural gas. This may cost $2 MM. This plant would contain a dehydrator, a regenerator of TEG and a flash tank to reduce methane emissions. The plant would use triethylene glycol as liquid desiccant with a purity of 99.6% to reduce the content of water from 1105mg/m^3 to the specifications limit of 64 mgH_2O /Sm^3 of gas. In an interview with a Marcellus expert it was found that the processing cost for this gas is insignificant to other heavy capital investments. After the processing, the gas produced from Susquehanna could be sent to pipelines.

3.5.7. BUILDING OF PIPELINES

Several factors determine the route of a pipeline and/or the placement of natural gas storage wells. They include, where the gas is needed and where it will come from, costs, the terrain over which the gas will be transported, the geographic location of underground storage, whether a pipeline can use an existing utility, right of way and whether there are routes that are less populated. Special consideration is also given to the proposed facility's impact on landowners and the environment.

There were various options available, each with particular physical and/or financial advantages and disadvantages. Some of the alternatives that were explored include:

- Building an entirely new pipeline,
- Conversion of an existing oil or product pipeline,
- Expansion or extension of an existing pipeline system

The least expensive option, often the quickest and easiest, and usually the one with the least impact environmentally, is to upgrade facilities on an existing route. Since this project explores virgin land, this option is not available. Next best option is to build entirely new pipelines network.

A preliminary plan was developed to build a natural gas pipeline and related facilities, which would have a design capacity to transport approximately 500 million cubic feet per day of gas from the location of gas gathering and processing plant to the nearest trunk line of Columbia Gas pipeline grid. The pipeline and related facilities would be designed such that the future capacity could be increased to approximately 700 million cubic feet per day with additional investments.

It will traverse Susquehanna County and be eventually connected at a T-Junction to the Columbia Gas Pipeline which is about 65 miles away from the location of our gas gathering and processing plant. While specific details of the project design are likely to change as additional engineering studies are conducted and market information is gained, the project is expected to consist of 65 miles of 35 inch diameter steel pipeline and a related 60,000 horsepower compressor station capable of transporting up to 700 million cubic feet per day of natural gas. Compressor stations, placed at intervals along the pipeline system, boost the pressure of gas to push the gas through the pipelines on its way to customers. Since the length of the pipeline is less than 100 miles, only one compressor station is needed to be built on the pipeline route.

Prior to commencing construction, securing a Certificate of Public Convenience and Necessity from the Federal Energy Regulatory Commission (FERC) is required. Also permits from the following agencies need to be secured

- U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA)
- U.S. Department of Transportation (DOT).
- US Army Corps of Engineers
- US Fish and Wildlife Commission.

Since the pipeline will run from Pennsylvania into New York, permits from Pennsylvania Department of Environmental Protection, New York State Department of Environmental Conservation, and New York State Historic Preservation Office are required.

Pipeline Design: The major components that will form the Susquehanna Pipeline Project are:

- Gas transmission pipelines from drilling and production locations to the Gas Treatment Plant
- A Gas Gathering and Treatment Plant (GGTP),
- A pipeline from the GGTP to the Columbia Gas Trunk line,

Five production stations have been proposed. Hence, the GTP would be located at a point that is equidistant from all five locations. It will be designed to remove carbon dioxide and other impurities from the natural gas stream to meet the pipeline quality gas specifications as mentioned later. These pipeline specifications would also require that the gas be compressed and chilled. The Mainline would be approximately 65 miles long, 35-inch diameter, and buried pipeline operating at 2,000 psi that extends from the GGTP to the nearest point of the Columbia Gas Trunk line which is situated on the New York/Pennsylvania border. Standard design codes states that all pipelines passing through populated areas reduce its maximum operating pressures for safety reasons. It has become common practice to maintain nominal pipe diameter but increase wall thickness in order to keep the working pressure rating more constant along the line. Project specifications have been determined to be in conformity with this design code.

When a new natural gas pipeline system is designed and built, the number and capacity of associated compressor stations is a key design feature. Thus, compressor stations would also be placed at required intervals to maintain gas flow rates. Since the region is susceptible to permafrost, the gas would be chilled to manage the mechanical strains on the pipe and mitigate potential impacts on frozen soils.

Natural Gas Liquids (NGLs) are also expected to be transported in the pipeline along with the natural gas.

The costs, technology, regulatory and environmental issues associated with the project have been assessed. While this assessment represents a significant engineering effort, design details (including design capacity, pipeline size, compressor location, etc.) are likely to change as engineering and permitting work progresses. The design process itself included the development of cost estimates for various possible combinations of pipe size, compression equipment, and inter-station distances to find the combination that minimizes transportation cost given the desired flexibility and expandability goals.

As mentioned earlier, pipeline from this project would be connecting to Columbia Gas pipeline network. Columbia Gas generally delivers natural gas to local gas distribution companies, which in turn distribute the gas to homes, businesses and factories. They also deliver gas directly to some end-users, such as electric generation facilities. Although we are unable to determine the total cost of this project at this stage, we have determined the cost implication of maintaining a "gas handling service relationship" with Columbia Gas. (Table 11) is a representation of the cost of transportation and storage as provided by Columbia Gas.

Development plan: The development of the final project design and obtaining firm financial commitments from customers, may take from 2 to 3 months, after which the project specifications are filed with the appropriate regulatory agency. On average, an interstate construction/expansion project may take about 3 years from the time it is first announced until it is placed in service. It may even be longer if it encounters major environmental obstacles, or public opposition.

The following sections show the Estimated Project Schedule /Proposed Development Activities for this project. It presents a conceptual timeline for planning and constructing the gas pipeline and related facilities. The overall timeline spans 3 years, from the start of Project Planning to mechanical completion, commissioning and commencement of commercial operations (first gas deliveries). This is a success-case schedule, i.e., it is based on the assumption that each major activity will be successfully completed in a timely manner. The key underlying premises to this schedule are that:

- Commercial negotiations with the States of New York and Pennsylvania are successfully concluded and key agreements are executed in time to allow the Project Planning phase to commence as soon as possible;
- There are no unanticipated delays in receiving access and key permits/approvals for all components of the project scope;

If issues arise or unanticipated delays occur, the schedule would be extended accordingly. During Project Planning, we will do additional work to establish a more definitive project timeline.

Route Selection: The selection of the route for the pipe affects materially, the costs of the pipeline. Preliminary selections should be made by a detailed check of aerial photographs and topography maps. Particular care would be taken to avoid, if possible, muskegs, sloughs, steep banks, ravines, etc. After a preliminary route has been selected, the route selected would be inspected and any particular trouble sports checked. Generally a straight line type of layout is considered best. Also, soil conditions would be checked to determine the existence of rocks, etc in the ground. Special crossing header and valve location would also be reviewed.

Survey and Right of Way Acquisitions: Right of way is obtained after route selection. These rights of way will allow our pipeline to cross the owners land. The exact location will be determined by the survey crew. This crew will follow the design maps and determine the exact location of the pipeline route. The survey party will then stake each side of the right of way on which the pipeline is to be built. The width of the right of way varies from about 33ft to 75ft or even more (10m to 25m). Generally, 50ft (45m) or greater of right of way is desirable for good pipelining. This will allow reasonable working room without going off the allowable right of way.

Procurement: The procurement aspect of the project involves the preparation of specifications, and purchasing of services, materials and equipment for the project. Early procurement would focus on long-lead materials and equipment to ensure timely project execution. However, most financial commitments would not be made until after the major permit decisions and authorizations have been secured, including the certificates from FERC.

Pipe, Valve and Fitting Ordering: After the design has been completed and the necessary permits obtained, the pipe would be placed on order. This will be done by taking off from a scale map the amount of pipe required and adding about 3% for changes in the grades (this of course can vary with topography) and about 1% for wastage. If time permits, the survey would be done and the pipe ordered after surveying. As soon as the details for connection, valving, etc is complete, these materials will be ordered as well.

Pre-Construction: Prior to arrival of pipe and the pipe-laying crews, extensive preparatory work would be required. For example, pipeline right-of-way and construction easements would be cleared, compressor sites and staging areas prepared, and construction camps set up. In addition, once pipe arrives, it shall be coated and delivered to staging areas.

Construction: The construction phase involves the fabrication, installation and construction of the project facilities, and would be dependent on seasonal conditions and availability of skilled resources. Project construction would cover the Gas Treatment Plant, Pipeline, Compressor Stations, and potentially an NGL Plant, with activities beginning with fabrication of equipment modules and stringing of pipe, and ending with final testing and functional checkouts leading to project commissioning.

Protection of Pipe: Normally, steel pipe is externally coated for corrosion protection. Some of the common external coating options are Coal Tar and Polyethylene type tapes – either field or factory applied such as yellow jacket. As an added means of protection, cathodic protection facilities shall be planned and added. These systems of course have to be custom designed to fit the soil conditions. The selection of the appropriate type of pipe is generally an economic one.

Pre-Commissioning and Commissioning: Commissioning and testing of the completed pipeline project usually takes about 1 to 3 weeks and involves subjecting the completed segments of the projects to hydrostatic and other required testing of the line in place.

After laying the pipeline, it will be pressure-tested according to government regulations. The preferable test media is water. However because of winter conditions (as is the case with the Appalachia), it is necessary to use an antifreeze or different fluid such as condensate, sweet gas or air. After the pipeline has been pressure-tested, the next step will be to displace the test media and start purging. After purging, the pipeline would be pressured up, either with sweet gas or the operating fluid, as a further check for leaks. If everything goes well, it is ready to be commissioned and put into use. During the commissioning phase, project personnel would work closely with operations personnel to prepare the equipment and facilities for actual operation and eventual delivery of first gas with subsequent ramp-up to full capacity.

3.6. POLICIES AND REGULATIONS OF GAS UTILIZATION

Different from the environmental issues in gas recovery, air pollution is critical issue in utilizing and conversion process. Even though water contamination is still controversial topic in these processes, once the facilities or pipelines are constructed, air pollution takes first place in the pollution problem. Thus, the regulations and policies will be focused on terms involving air pollution.

Before constructing processing and conditioning facilities, compressor stations and pipelines, the business planners should consider the regulations and laws complicatedly related to each other. Laws regulate the process of gas conversion and facility construction with strict demands of keeping a standard such as emission allotment or water contamination. For example, Clean Air Act regulates the amount of air pollutant emitted from stationary sources and mobile sources. Thus the capacity of processing and conditioning facility should be limited by the total pollutant emission rate.

Among the regulations and policies stands The FERC (Federal Energy Regulatory Commission), replaced for the FPC in 1977. The FERC has supervised the whole process - from well-head to end-users – since it has been established. The FERC has such a mission to follow;

"*The FERC(Federal Energy Regulatory Commission) regulates many aspects of interstate gas transmission pipeline operation, including approval, permitting and sitting for new pipeline facilities(largely an assessment of the public need for a project versus its landowner and environmental impacts), as well as transmission rates that pipelines are permitted to charge for interstate shipments*." (122)

The FERC presides over the running of processing and conditioning as well as pipeline construction to check whether the business plans meet the requirement of several regulations and laws. The regulations and the laws are as below;

- The Natural Gas Act of 1938

- National Environmental Policy Act of 1969
- Federal Water Pollution Control Act (Clean Air Act)
- Coastal Zone Management Act
- Endangered Species Act
- Clean Air Act
- National Historic Improvement Act of 2002
- The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006

All regulations and laws are important. However in this section, the Clean Air Act is main focus as it has the greatest impact in terms of environment pollution.

3.6.1. GATHERING AND REFINERY FACILITY

3.6.1.1. STANDARD OF EMISSION

The crude gas from each well head is gathered at the gathering facility and then sent to the processing and conditioning facility through the pipelines. Each facility emits air pollutants inevitably. The air pollutants emitted from industrial facilities are directly regulated by the Clean Air Act, which was last amended in 1990. Apparently, the pollutants are lethal and harmful to human health and that of animals. The environment is affected by the pollutant as well. Thus most plants, factories, and facilities should meet the air quality equivalent to the NAAQS. (National Ambient Air Quality Standards)

NAAQS (National Ambient Air Quality Standards)

This standard is applied to all industrial facilities and residential use when they would generate air emissions. "*The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatic, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility damage to animals, crops, vegetation, and buildings*." (123)

Most pollutants emitted from refinery plant are carbon monoxide, sulfur dioxide and nitrogen dioxide when the crude gas is refined. According to the NAAQS, the refinery plant should not emit these air pollutants in excess of certain predefined thresholds. In addition to NAAQS, there are environmental assessment programs to be considered under CAA (Clean Air Act). Two most important programs are NSR (New Source Review) and PSD (Prevention of Significant Deterioration).

The New Source Review (NSR) and Prevention of Significant Deterioration (PSD)

"*This program applies to new source construction and proposals to conduct major modifications of existing industrial facilities that are located in "non-attainment" areas (i.e., regions with poor air quality that do not satisfy the National Ambient Air Quality Standards), while the "Prevention of Significant Deterioration" requirements apply to project proposals that are located in areas which are in* *"attainment" with applicable National Ambient Air Quality Standards (i.e., ambient air quality in the region surrounding the new or modified source complies with the national standards)."* (124)

Usually processing and conditioning plants whether they are built in urban or isolate areas they usually satisfy the NAAQS. Thus PSD should be observed when operating the facility.

3.6.1.2. PENALTIES

The Clean Air Act has the penalty clause when the plants violate the guideline of emission. The assessment of violation of CAA consists of complicate criteria. Simply put, it is based on amount of pollutant, sensitivity to the environment, toxicity of pollutant, the length of time a violation continues and size of violator. Each category has its own standard level of assessment. Natural gas processing and conditioning facilities fall under the "Clean Air Act, Stationary Source Civil Penalty Policy, B.19. Appendix VI 'Volatile Hazardous Air Pollutant Penalty Policy'". The penalty is usually a fine determined by Penalty Calculation Worksheet. (125)

3.6.2. PIPELINE FACILITIES

The constructions of pipelines and compressor stations are regulated by the FERC too. The FERC has single mindedly pursued the efficient management and consumer convenience with regulation along with deregulation where they felt necessary. Under the current regulatory environment, only pipelines and local distribution companies (LDCs) are directly regulated with respect to the services they provide. It oversees gas companies that have significant market power and is keeping tabs on companies so that they do not abuse their monopoly position. FERC's regulatory have these objectives;

- Preventing discriminatory or preferential service.
- Preventing inefficient investment and unfair pricing.
- Ensuring high quality service.
- Preventing wasteful duplication of facilities.
- Acting as a surrogate for competition where competition does not or cannot exist.
- Promoting a secure, high-quality, environmentally sound energy infrastructure through the use of consistent policies.
- Where possible, promoting the introduction of well functioning competitive markets in place of traditional regulation.
- Protecting customers and market participants through oversight of changing energy markets, including mitigating market power and ensuring fair and just market outcomes for all participants. (87)

In terms of environmental issues, the U.S. Environmental Protection Agency assists the FERC and/or State authorities in determining if the environmental impacts of a pipeline development project and make sure they meet acceptable guidelines.

3.6.2.1. PIPELINE CONSTRUCTION

"*The construction of pipelines and related infrastructure can also trigger a variety of CAA requirements due to air emissions – principally diesel emissions – from equipment used in the construction of the project.*" (124) Depending on the size of the project – pipeline construction, distance, size of pipeline, etc, NSR or PSD should be considered. In other words, air pollution is not an important factor in case of small project. Later, after the construction is completed, the pipeline itself will not emit the air pollutants.

3.6.2.2. COMPRESSOR STATION

Compressor station is the facility used for long distance transporting of natural gas. The station compresses the natural gas with the help of devices like compressors, gas heaters and metering equipments, etc. This facility is also regulated by NAAQS and PSD. From time to time the station will vent natural gas during pipeline maintenance or equipment repair work. In such cases, natural gas is released into the air. This amount does not seriously impact air pollution. Also for processing and conditioning, the penalty for this facility applied is similar. The authority assesses the environmental impact by amount of pollutant emission and then the authority fines and orders to fix the violation.

3.6.2.3. MOBILE AIR POLLUTION SOURCE

When constructing the gas process plants, pipelines, and compressor stations, the construction material such as pipes and water are carried by heavy duty vehicles. These vehicles usually are diesel engine operated and are pointed out as one of the main pollutant emitters. It is called mobile pollution source. It is widely accepted that emissions from diesel engines cause adverse health effects. For example, Benzene can cause a cancer when exposed in long term. The Clean Air Act set a specific emission standard of air toxic pollutants in 1990. Two toxics are regulated by the Act, those being hydrocarbons and particulate matter. Every heavy vehicle should get an inspection periodically by the Act on how much pollutants the vehicle emits. Then in 2007, Pennsylvania State adopted a regulation of heavy duty vehicles that was ratified in California State. Pennsylvania's regulations can be found in 25 Pa. Code Section 126.501 with definitions in Section 121.
(www.pacode.com/secure/data/025/chapter126/subchapEtoc.html).

The basic notion of the regulation is limiting pollutant emission imposed by vehicle's age. So, new vehicles should emit less pollutant than old ones. This applies to all diesel engines that are used on construction site. With respect to vehicle inspection regulation depending on the magnitude of construction, NSR or PSD might be needed. In this case, NAAQS will be applied as the standard of air pollution.

3.6.3. MASS CONSUMER OF NATURAL GAS

3.6.3.1. POLICY FOR GAS INDUSTRY

Natural gas is known for having the least environmental impact among all the fossil fuels. For this reason, Pennsylvania State has set up a policy towards natural gas to reduce the air pollutants and promote its use instead of petroleum. According to the natural gas import statistics of Pennsylvania, natural gas is consumed more than production in Pennsylvania. Around 85% natural gas is imported from other states or Canada. Many experts predict that the consumption will keep increasing as the years go by. The Marcellus will be an alternative natural gas source in Pennsylvania. The policy for natural gas produced from the Marcellus will be introduced in this section.

Pennsylvania State has its own gas industry policy and aims to meet it. The policies are focused on reducing gas consumption and elevating energy efficiency through tax incentives, funds for the technology development and so forth. There are seven major policies including climate change roadmap and they are summarized as below;

Vehicle Policy of Pennsylvania State: Pennsylvania adopted California's Low-Emission Vehicle Program in 2006, committing to a 30% reduction in average new vehicle greenhouse gas emissions from 2002 levels by 2016. California has a very stringent regulation for vehicle emission as compared to other states. The regulation is directed to reducing smog-forming emission from passenger cars and trucks. Pennsylvania State has 11,086,810 cars (2006). (126)

Electric Utility sector policies: This policy is about implementing energy efficient improvements. Currently there is only one utility energy efficiency program and it is run by West Penn Power. The company provides loans so that the residential homeowners can invest into the energy efficiency elevation for their own house. But recently, a new law has been approved in state legislature. The law demands that electric distribution companies should reduce energy consumption by a minimum 1% by May 31, 2011, increasing to 3% by May 31, 2013, and to reduce peak demand by 4.5% by May 31, 2013.

Tax incentives: In July 2008, Alternative Energy Investment Act took effect. The Act will create $650 million towards an alternative energy fund. The fund will be used to help developing energy efficiency technology, improving the energy efficiency of existing houses and buildings and supporting loan, grants and rebates for energy efficiency improvements to homes and small business.

Building Codes: Pennsylvania has a state-wide mandatory residential building code based on the 2006 IECC or 2006 IRC, Chapter 11. Residential buildings can also comply with Pennsylvania's Alternative Residential Energy Provisions [2006]. Commercial buildings must also meet the 2006 IECC, with reference to ASHRAE 90.1 – 2004.

Clean Distributed Generation: Pennsylvania, in accordance with its Alternative Energy Portfolio Standards Act of 2004, adopted interconnection standards for Distributed Generation (DG), including CHP, in August 2006. The standards cover four different tiers of interconnection, up to 2MW in size.

Specific technical screens and timelines are associated with each level of inter connection. Pennsylvania's standards were based upon the model interconnection standards promulgated by the Mid-Atlantic Distributed Resources Initiative Working Group, and also adhere to the technical standards delineated in the IEEE 1547 interconnection standards.

Smart Growth Policies: Pennsylvania State has two acts to control sprawl and encourage development in core urban areas. The Acts called the "Growing Greener" and "Growing Smarter," were enacted in 2000. Pennsylvania State reserved $650 million to address environmental priorities according to the "Growing Greener" act.

Climate Change Roadmap for Pennsylvania: In June 2007, the Pennsylvania Environment Council released its Climate Change Roadmap for Pennsylvania. The roadmap was developed with the help of academic, agriculture, capital investment, energy generation, environmental, and government stakeholders inputs, presenting a series of policy and action item recommendations to reduce greenhouse gas emissions in Pennsylvania.

3.6.3.2. CLIMATE CHANGE ROAD MAP

Pennsylvania is emitting 1% of greenhouse gas (GHG) of the whole world and has the 3rd place in ranking of GHS emitted in the U.S. This level puts Pennsylvania in the league of the top 25 emitting nations in the world. (88) In order to cut down the amount of GHG emission and save the environment, and also to take a leading position of clean technology industry, the roadmap project was launched. The aim of the project was to produce:

- An inventory and forecast of the Commonwealth's GHG emissions.
- Policy recommendations for reducing of Pennsylvania's emissions.
- Appropriate emission goals or targets for Pennsylvania, and a near-term strategy for pursuing them. (88)

In brief, the roadmap presents a "base case" scenario reflecting current policies, Pennsylvania's GHG emissions are projected to grow in the coming years at roughly 10% per decade. However, Pennsylvania could lower and ultimately reverse this growth if it joins other states in setting goals for reducing GHG emissions, and adopting the necessary supporting policies. (88)

Estimates of the GHG emissions impacts of these policies indicate that they could support a goal of reducing Pennsylvania's emissions to 25 percent below 2000 levels by the year 2025. Within the recommended economy-wide approach to reducing GHG emissions, five outcomes would be critical to achieving this goal.

- Cutting electricity demand in 2025 equal to current levels by applying an aggressive portfolio of energy efficiency policies.

- Strengthening Pennsylvania's Alternative Energy Portfolio Standard (AEPS) with a target of 25% alternative sources and a requirement that non-renewable AEPS sources be carbon-neutral by 2025, in keeping with spirit of the 25x'25 vision.
- Increasing renewable transportation fuels to supply 25 percent of the Commonwealth's needs, consistent with the 25x'25 vision.
- Implementation of a national cap-and-trade system that would achieve significant reductions from some of Pennsylvania's existing power plants and industrial plants that burn fossil fuels.
- Achieving the full commercialization of geological sequestration of GHG emissions by no later than 2025. (88)

In order to accomplish with these five outcomes, continuous effort of government and non-governmental cooperation are strongly needed. The roadmap recommends a long-term emissions reduction goal for the Commonwealth that is based on the level of global reductions leading climate scientists recommend in order to stabilize GHG concentrations. (88)

Pennsylvania is pursuing to take a leading position in climate change business by executing this roadmap. The agenda will help Pennsylvania in attracting new investment, industries and job that are connected with clean technology.

- 25x'25 vision (127)

”25x'25" is a rallying cry for renewable energy and a goal for America – to get 25 percent of our energy from renewable resources like wind, solar, and biofuels by the year 2025.

Increasing America's renewable energy use will:

- Bring new technologies to market and save consumers money.
- Reduce our dependence on oil from the Middle East.
- Create good new jobs in rural America.
- Clean up the air and help reduce urban smog and greenhouse gas emissions.

3.7. ECONOMIC EVALUATION

Total cost associated with above mentioned activities were obtained. All of these costs have not been published in any literature work. They have been obtained by personal interview of company representatives.

Exploration Cost: The initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well is called 'Exploration'. Cost belonging to these activities comes under exploration cost. There are several kinds of Exploration, namely, Geochemical, Geophysical and Seismic. This cost has been taken as $0.9/Mcf.

Administrative Cost: Expense incurred in controlling and directing an organization, but not directly identifiable with financing, marketing, or production operations. Salaries (Accountants, Engineers, and Laymen) and costs of general services fall under this heading. Administrative costs are related to the organization as a whole. This was considered as 10% of total expenses for this study.

Drilling Cost: This cost includes the cost of drilling, fracturing and completion of a well. A cost of 4 million per well was taken in this analysis. This is the approximate cost a service company demands to complete a well.

Infrastructure Cost: This cost is associated with the money spent on facilities viz. Offices, Site, Roads, Gathering station, Processing Plant, and Pipelines. In an interview, this cost was reported in $/Mcf by Rex Energy. It was not possible to get the further break-up of cost related with each component. This was $1/Mcf.

Operating Cost: This Cost is involved in running the production-operations smoothly. This includes the cost associated with Energy, Chemicals, Machinery and maintenance. This was taken as $1.1/MCF (source Rex/Quest Energy).

Royalty: A payment made for the use of property, especially natural resource. The amount is usually a percentage of revenues obtained through its use. This amount is calculated as certain percentage of revenue (before tax) generated from the production sale. It was considered as 12.5% for this project.

Lease Cost: This cost varies ($500-$2500/acre) with market price of the gas. It was taken as $1500/acre.

Reclamation cost: Once operations are complete at a site. Regulation states that it should be left it the way it was. This costs $20,000-$30,000 per well to the project.

Salvage Value: The estimated value of an asset at the end of its useful life. Ottrivani, CFO Rex energy explained that usually its zero for a long projects. As this project is for 20 years, this value was considered zero.

Revenues: Money generated from sale of gas.

Fore coming analysis would follow the procedure below.

Step 1. Analysis of the economic attractiveness of the project alternative without the revenue from carbon credits using an IRR calculation and comparison of the results with a reasonable expected return on investment in Pennsylvania. The results show that the project is not an economically attractive course of action if it is employed for a period of less than seven years.

Step 2. The only other plausible scenario is to continue the project for a long time till the gas wells produces. This scenario is determined as the baseline scenario based on an analysis of current practices and current and foreseeable regulations in the waste management sector.

Step 3. Calculate a conservative IRR for the proposed project activity not taking carbon finance into account. The calculation must use the incremental investment as well as operation, maintenance and all other costs to the proposed project activity, and it must include all revenues generated by the project activity except carbon revenues. An IRR is calculated conservatively, if assumptions made tend to result in a rather higher than a lower IRR. Investment is in initial 10 years so average value has been used for the analysis. Rate of inflation and increasing cost have not been taken in the account.

Step 4. Determine that the project IRR is clearly and significantly lower than a conservatively (i.e. rather low) expected and acceptable IRR for this or a comparable project type in this country.

Step 5. Conclude that the project is therefore economically attractive.

Step 6. Do sensitivity analysis for different variables.

Financial analysis is carried out, Given that the main potential financial returns derived from the sale of gas. Feasibility of this project is, thus, dependent on factors related to energy sector and *to the cost of lease/infrastructure.*

NPV calculations indicate that this project has a net present value in excess of $ 600 million with an IRR of 20.06%. Sensitivity analysis shows that the viability of this project is highly dependent on price of the gas in market. ***Table 29*** and ***Table 30*** show the Net NPV change and % NPV change with variation in different parameters.

Cost of producing one thousand cubic feet comes out to be $5.03. NPV is 7% of the total cost incurred during the life of the project. However, wells would keep on producing for 20 more years which could increase this percentage.

3.8. SWOT ANALYSIS

SWOT analysis must first start with defining a desired end state or objective. A SWOT analysis may be incorporated into the strategic planning model. An example of a strategic planning technique that incorporates an objective-driven SWOT analysis is Strategic

- **S**trengths: Attributes of the person those are helpful to achieving the objective.
- **W**eaknesses: Attributes of the person those are harmful to achieving the objective.
- **O**pportunities: External conditions those are helpful to achieving the objective.
- **T**hreats: External conditions which could do damage to the business's performance.

These four aspects were analyzed with respect to this project (see ***Figure 27***).

3.9. CONTRIBUTION TO SUSTAINABLE DEVELOPMENT

The project activity's contributions to sustainable development are:

- Reducing the dependence on import of exhaustible fossil fuels.
- Reducing air pollution by sequestering the CO_2 emitted from coal-fired power plants.
- Reducing the adverse health impacts from air pollution.
- Contributing to local economic development and employment creation.
- Reducing the emissions of greenhouse gases, to combat global climate change.

3.10. FUTURE DEVELOPMENT SCOPE

CO_2 induced stimulation: As discussed in the literature review, carbon dioxide can be used in place of water for hydraulic fracturing operations.

To implement a successful treatment with carbon dioxide will require experimental data. Five wells in the first year will be the guinea pigs for the test. Based on the success of this study further wells will be treated with carbon dioxide or the idea will be totally scrapped. If successful, it could be implemented for all 60 wells which will be drilled in the location for the next 8 years. A fluid with 80% carbon dioxide and remaining a 40% methanol in water solvent has good proppant carrying properties when mixed with cross linked polymers like gaur. Carbon dioxide captured from an IGCC plant located in Pennsylvania will be used for this pilot study. The amount of carbon dioxide needed for this activity will be far greater than the water amount. This will result in additional revenue via carbon credits. As of now at the Chicago Climate Exchange the cost of a ton of carbon dioxide is $1.6. The approximate amount of carbon dioxide needed in thousands of tones.

Microwave induced fracture stimulation: As part of this project, stimulation method was studied and promising characteristics of Shale was found for Microwave stimulation. They are following:

- Shale has naturally developed conduits see ***Figure 28***, so it is could be easy to generate macro-fractures from micro-fractures.
- Shale is a very soft and friable rock as discussed earlier and can be fractured.
- Microwave could generate fractures in a rock if it has moisture content. It was found in literature that Moisture/Water Content of shale is (8.5-20) % wt (128).

Pyrolysis of Organic content (oil and gas) is successful (129) and it was found that microwave develops new fractures in the sample (refer ***Figure 29*** and ***Figure 30***). Moreover, Microwave is an energy efficient method for materials processing, says Dr. Agrawal (MRI, PSU). It can be fine tuned to generate effect in particular molecules in a sample, he added. This could prove as non hazardous technology for stimulation.

3.11. CONCLUSION

A critical assessment of sustainable gas recovery, conversion, utilization and environmental management in the Marcellus Shale bas been conducted and a proposal to safely, economically and cost effective carry out exploration and production activities in the Susquehanna County, presented. Given the scope and scale of the entire project, significant demands would be placed on material resources, equipment and manpower. The project will provide significant number of employment opportunities for engineers, management personnel, landsmen, artisans and other unskilled laborers, not only in the host communities but also in the states of Pennsylvania and New York in general. We intend to fully comply with all valid federal, state, and municipal laws relating to hiring local residents to work on the various aspects of the project.

Based on the results of our Net Present Value Calculations, this proposal is viewed as a commercially and economically viable project. This is because, in addition to manpower development, breakeven will occur in the first few years(6-7) of the life of the project and returns on investment will continue to be recorded as long as there are no drastic and/or unforeseen drops in the market price of natural gas. We therefore recommend this project for further evaluation and investment.

APPENDICES

A. Figures

B. Tables

C. Calculations

APPENDIX A: FIGURES

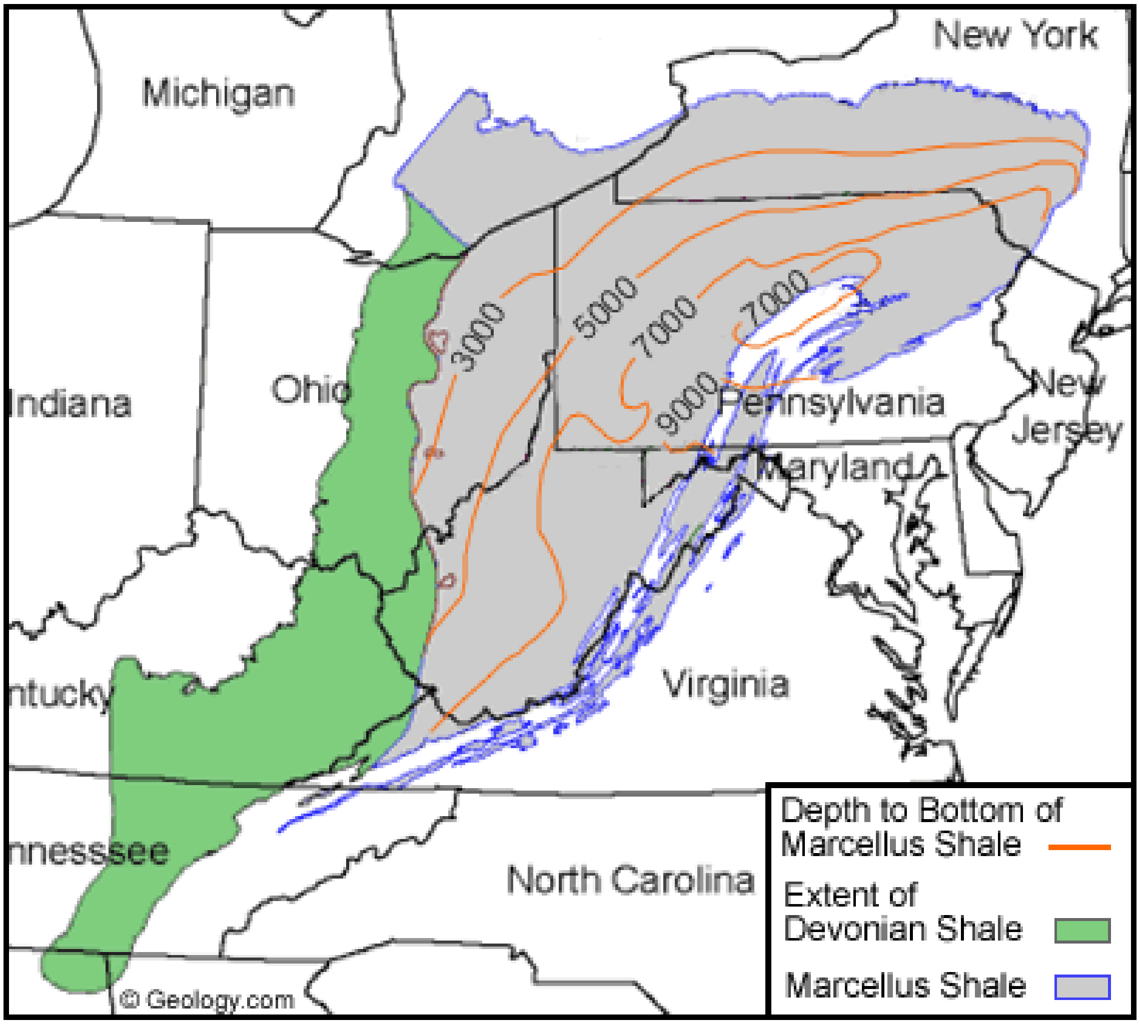


Figure 1 Depth of Marcellus shale formation

This map shows the approximate depth to the base of the Marcellus Shale. It was prepared using the map by Robert Milici and Christopher Swezey above and adding depth-to-Marcellus contours published by Wallace de Witt and others, 1993, United States Department of Energy Report: The Atlas of Major Appalachian Gas Plays.

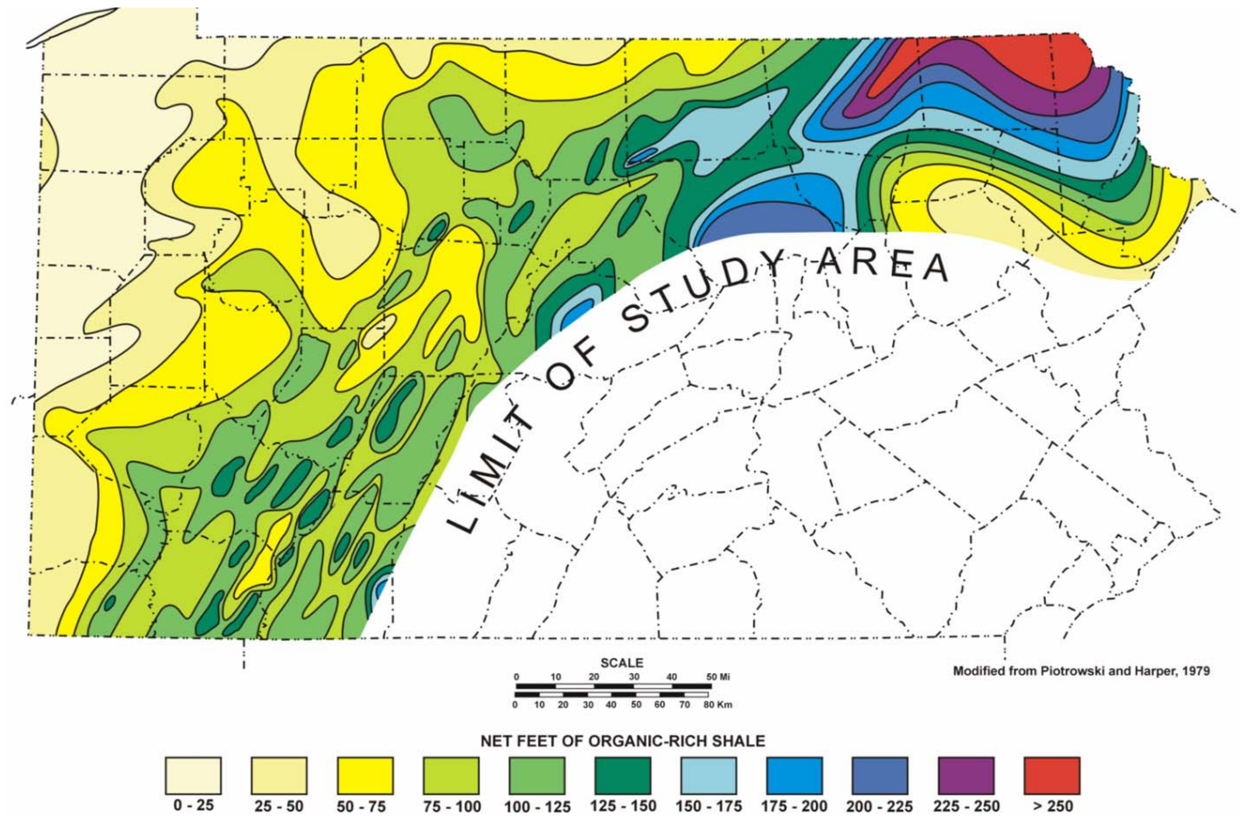


Figure 2. Net feet of organic-rich shale in the middle devonian marcellus formation in Pennsylvania

A map of Pennsylvania showing the net feet of organic-rich shale in the Marcellus Formation. John Harper of the Pennsylvania Geological Survey believes that the thickness of organic-rich shale may be more important than the total Marcellus thickness in assessing the production potential of a well site. Map after Piotrowski, R.G. and Harper, J.A., 1979.

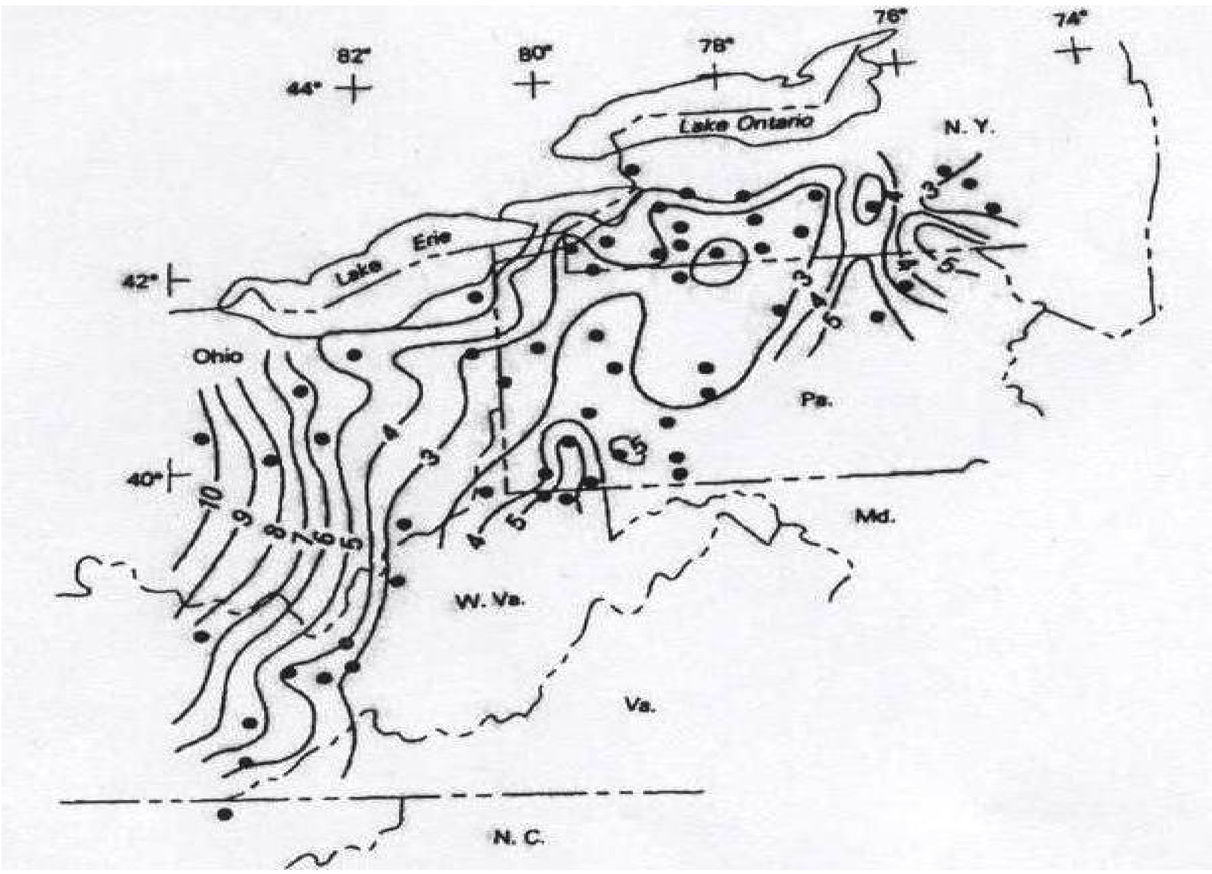


Figure 3. Average Organic Content of the black shale of Middle and Devonian age (Numbers indicates %)

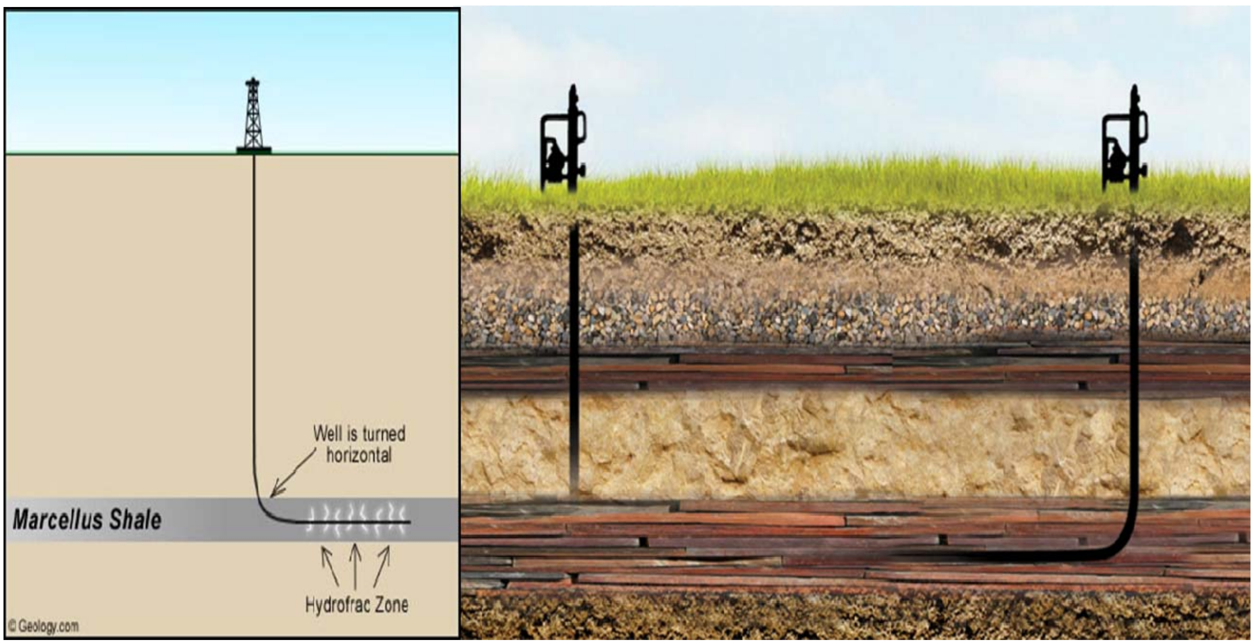


Figure 4. Drilling Type (Vertical and Horizontal drilling)

The most promising wells drilled into the Marcellus employ two technologies that are relatively new to Appalachian Basin gas shale production. One is horizontal drilling, in which a vertical well is deviated to horizontal so that it will penetrate a maximum number of vertical rock fractures and penetrate a maximum distance of gas-bearing rock. The second is "hydrofracing" (or hydraulic fracturing). With this technique, a portion of the well is sealed off and water is pumped in to produce a pressure that is high enough to fracture the surrounding rock. The result is a highly fractured reservoir penetrated by a long length of well bore. (Geology.com)

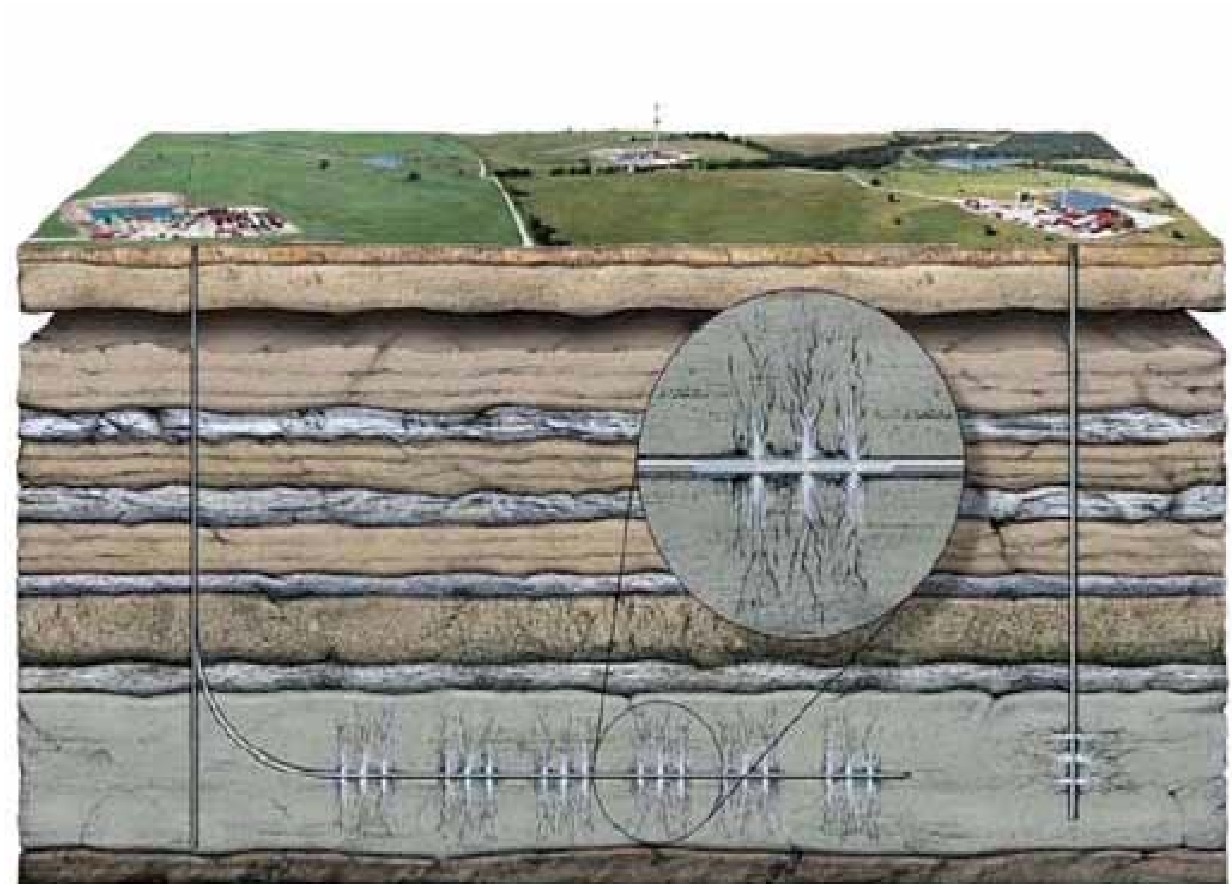


Figure 5. Reaching spot by Drilling Type (Vertical and Horizontal drilling)

Illustration from Pennsylvania DEP web site of underground parts of horizontal vs. vertical drilling and fracing of Marcellus Shale well from Pennsylvania DEP web site

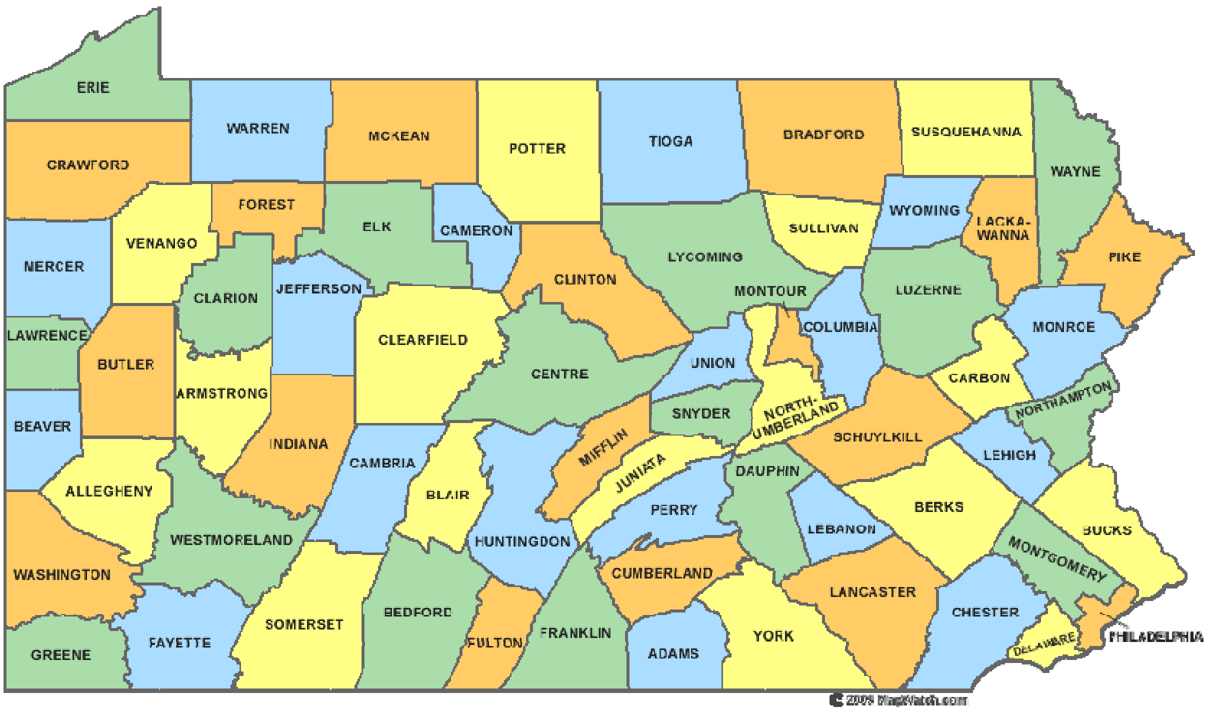


Figure 6. Political map of Pennsylvania County

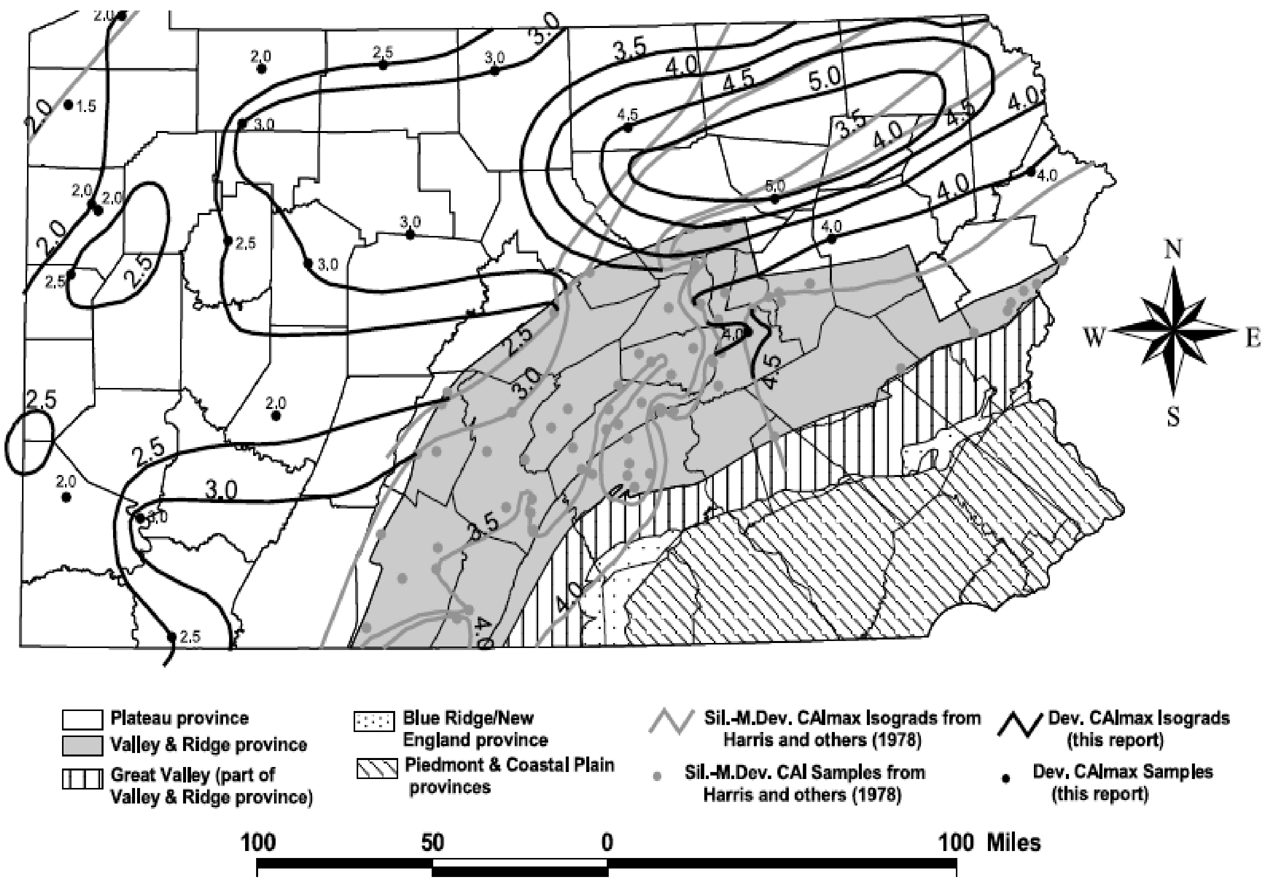


Figure 7. Devonian maximum Conodont Alteration Index (CAI)max isograds (11)

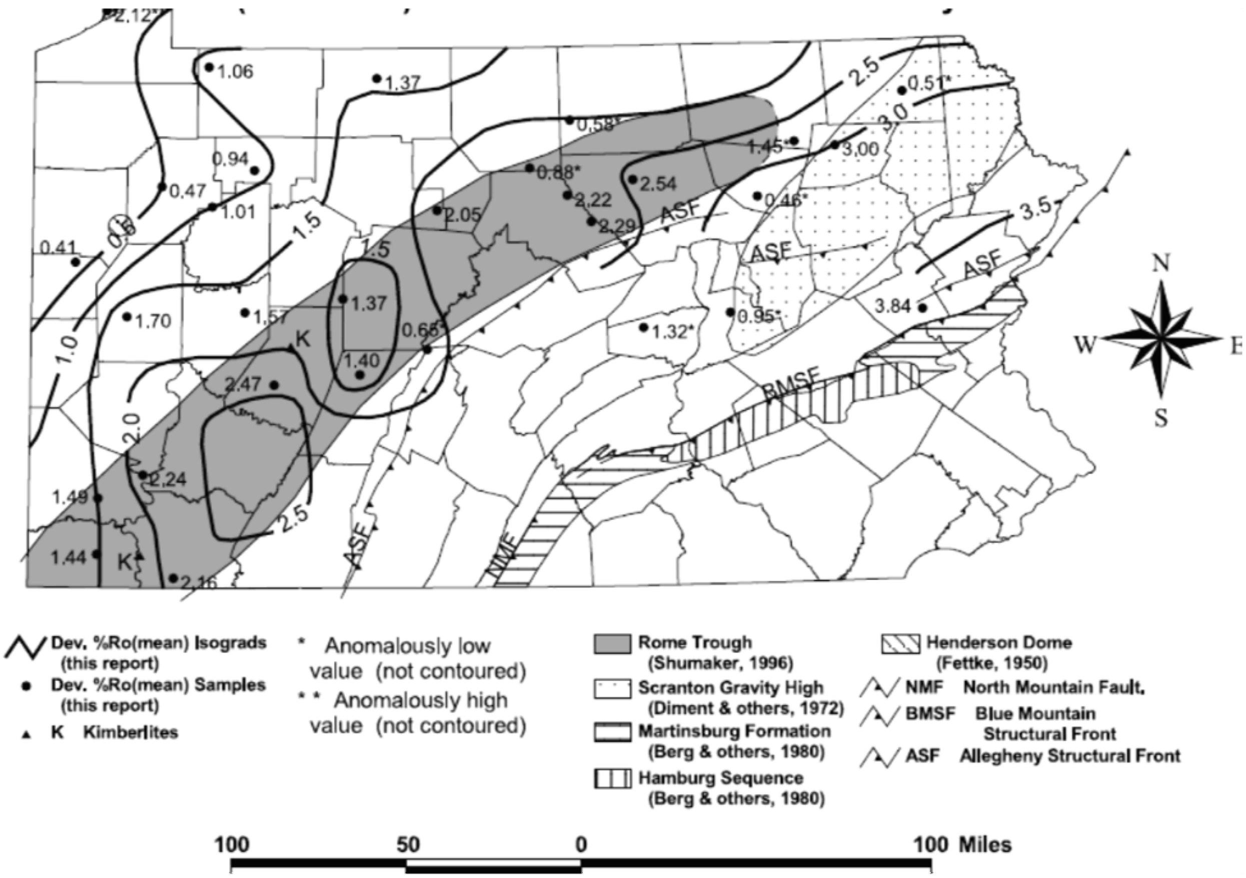


Figure 8. Devonian Vitrinite Alteration Index (CAI)max isograds (11)

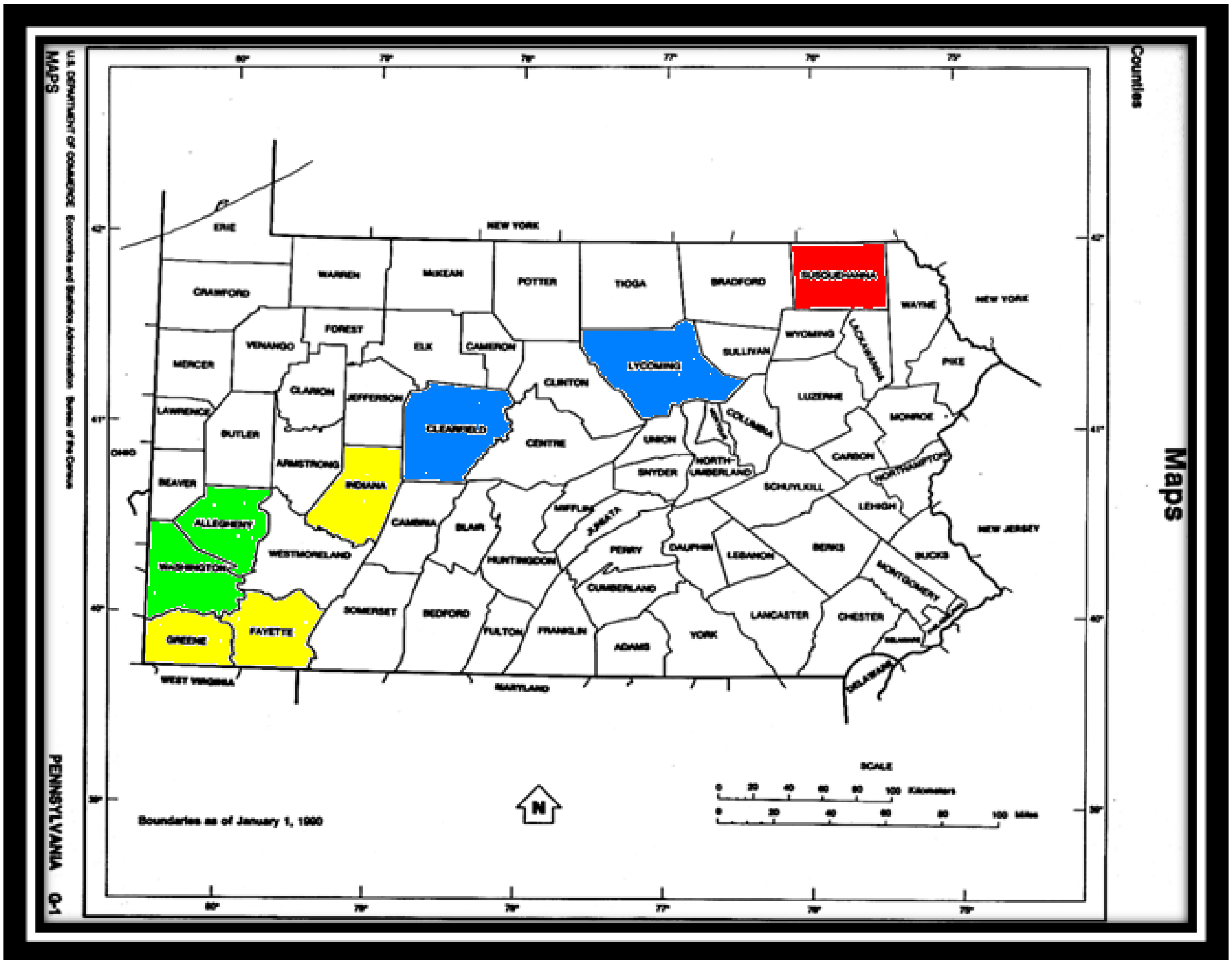


Figure 9. Degree of fracture porosity in eight counties

- Red: Good Fracture Porosity
- Yellow: Medium Fracture Porosity
- Blue: Poor Fracture Porosity
- Green: Very Poor Fracture Porosity

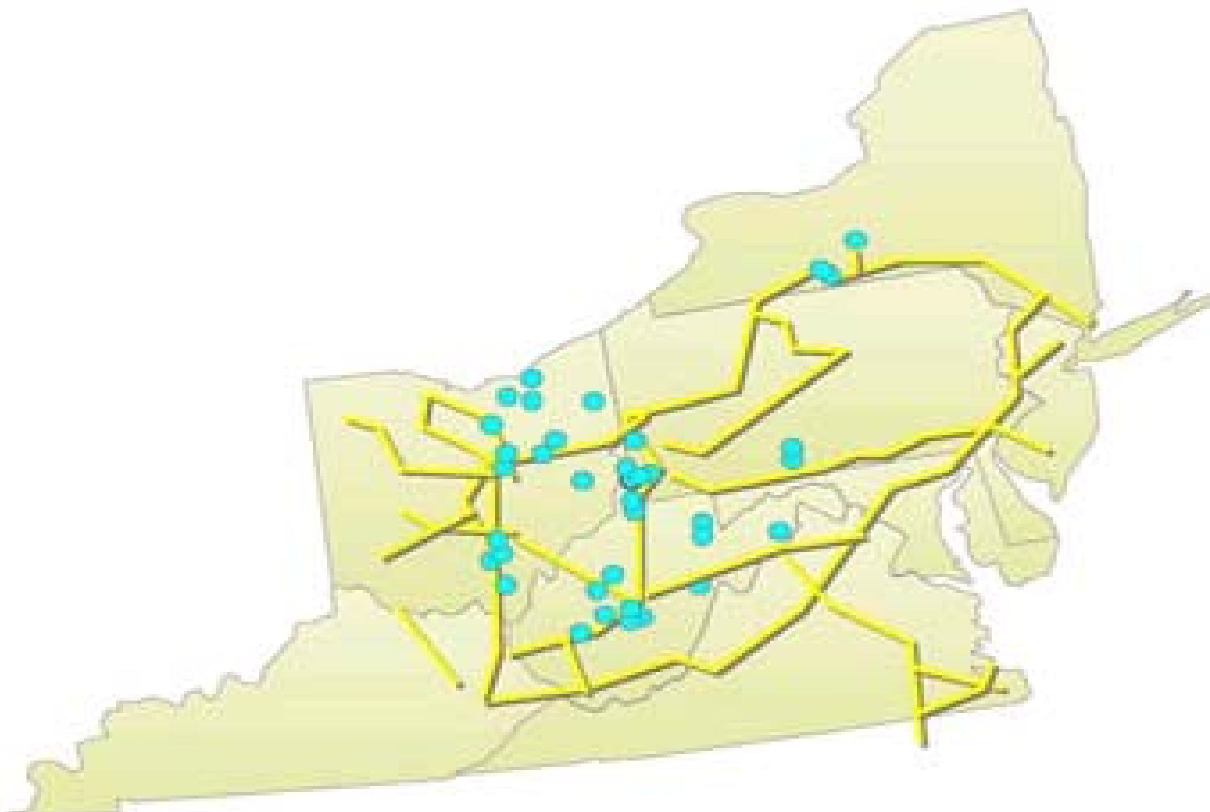


Figure 10. Columbia Gas Pipeline Network

[redacted]

[redacted]

[redacted]

[redacted]

Figure 11. Location of Land leased for E&P Activities

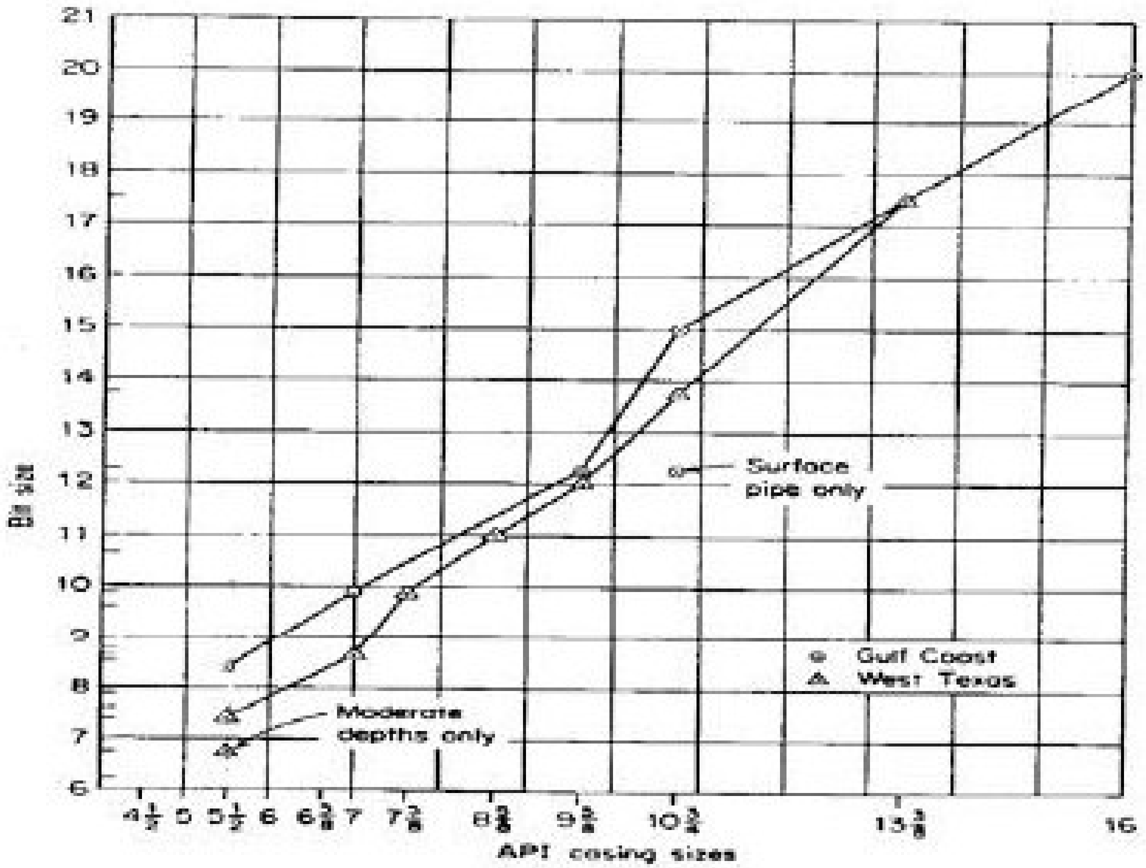


Figure 12. Casing-bit programs (Source: Carl Gatlin, Petroleum Engineering, Drilling and Well Completions, Prentice Hall, Inc., 1960)

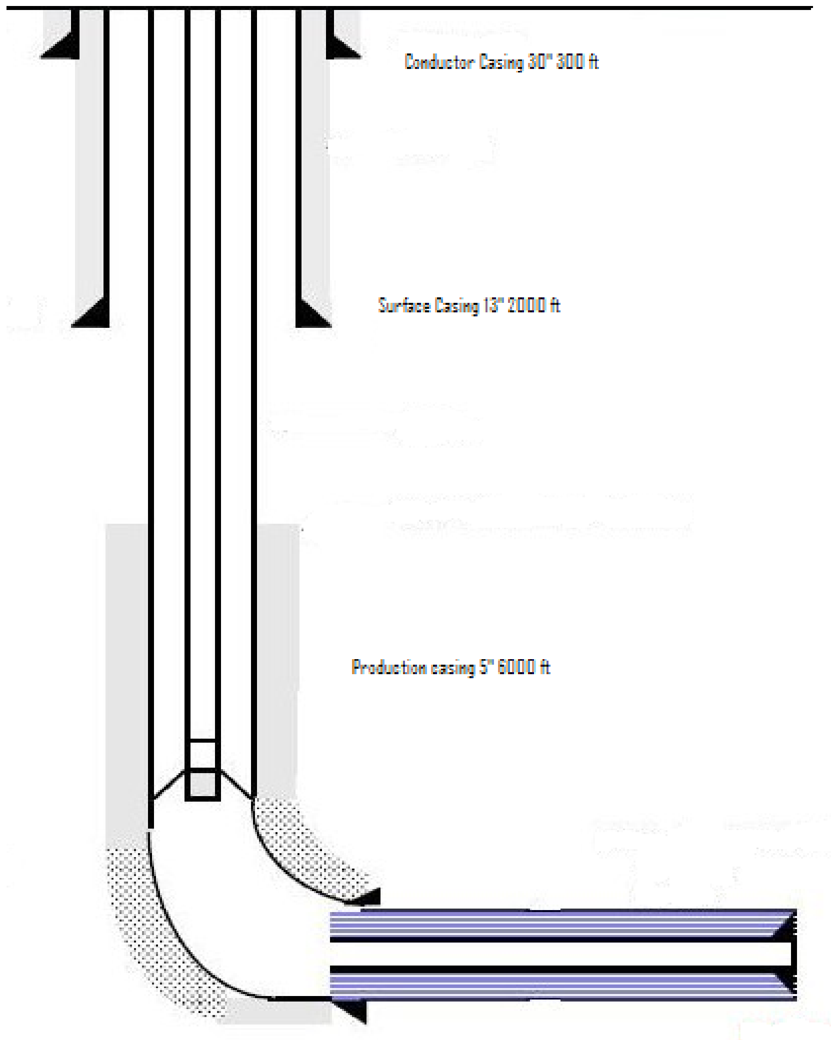


Figure 13. Setting depths of various casings

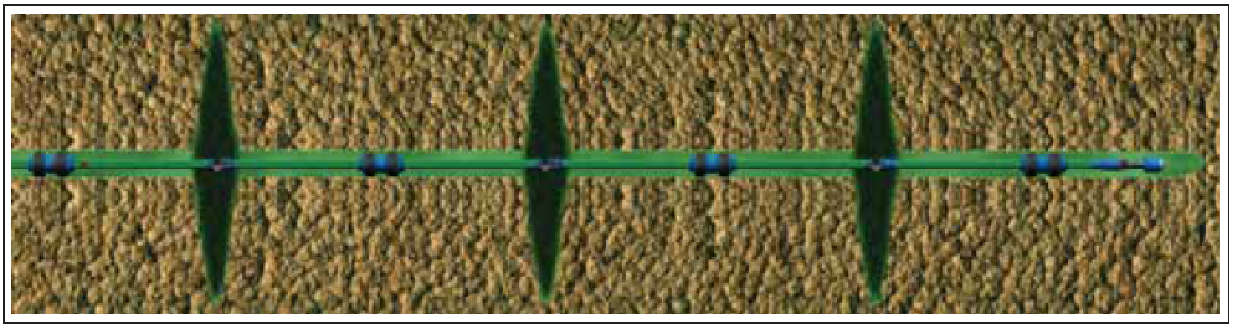


Figure 14. Stages in frac job (Source: Schlumberger Global oilfield and information services company)

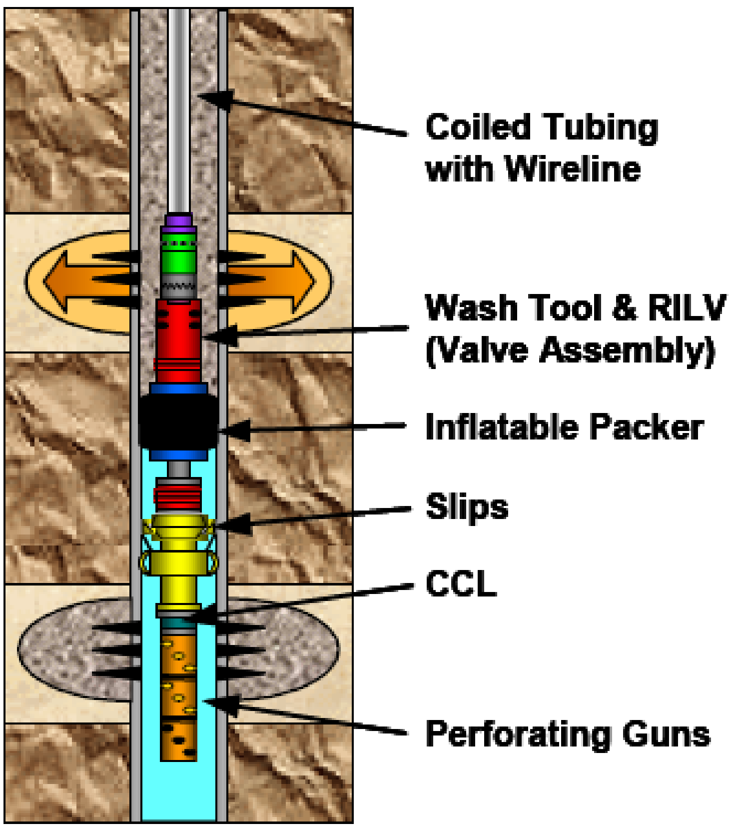


Figure 15. ACT-Frac bottom-hole assembly (Source: SPE Paper, Advanced Multi stage stimulation technology, After Lonnes,2005)

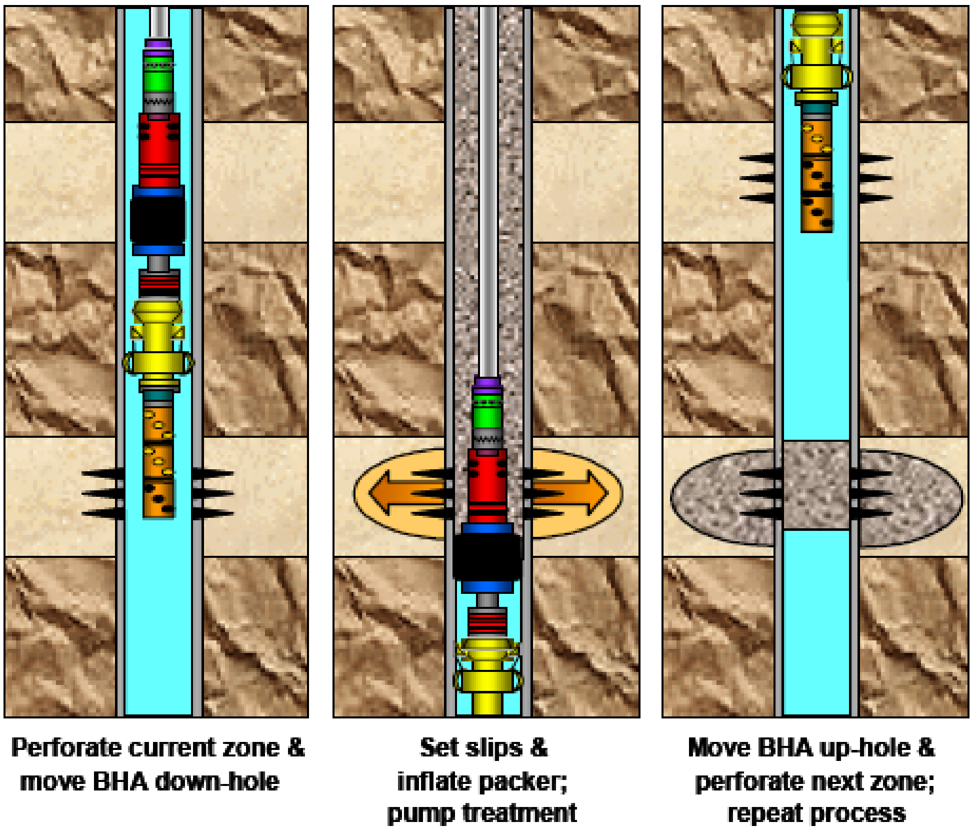


Figure 16. ACT-Frac stimulation process(Source: SPE Paper, Advanced Multi stage stimulation technology, After Lonnes,2005)

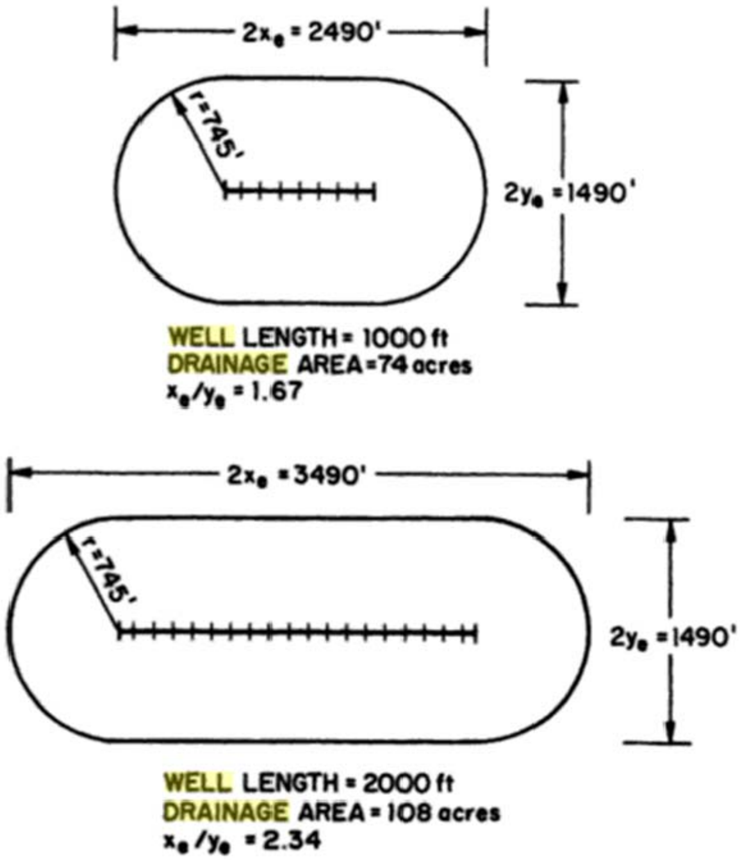


Figure 17. Drainage areas of 1000 and 2000-ft-long horizontal wells (Source : Book "Horizontal Well Technology" S.D. Joshi)

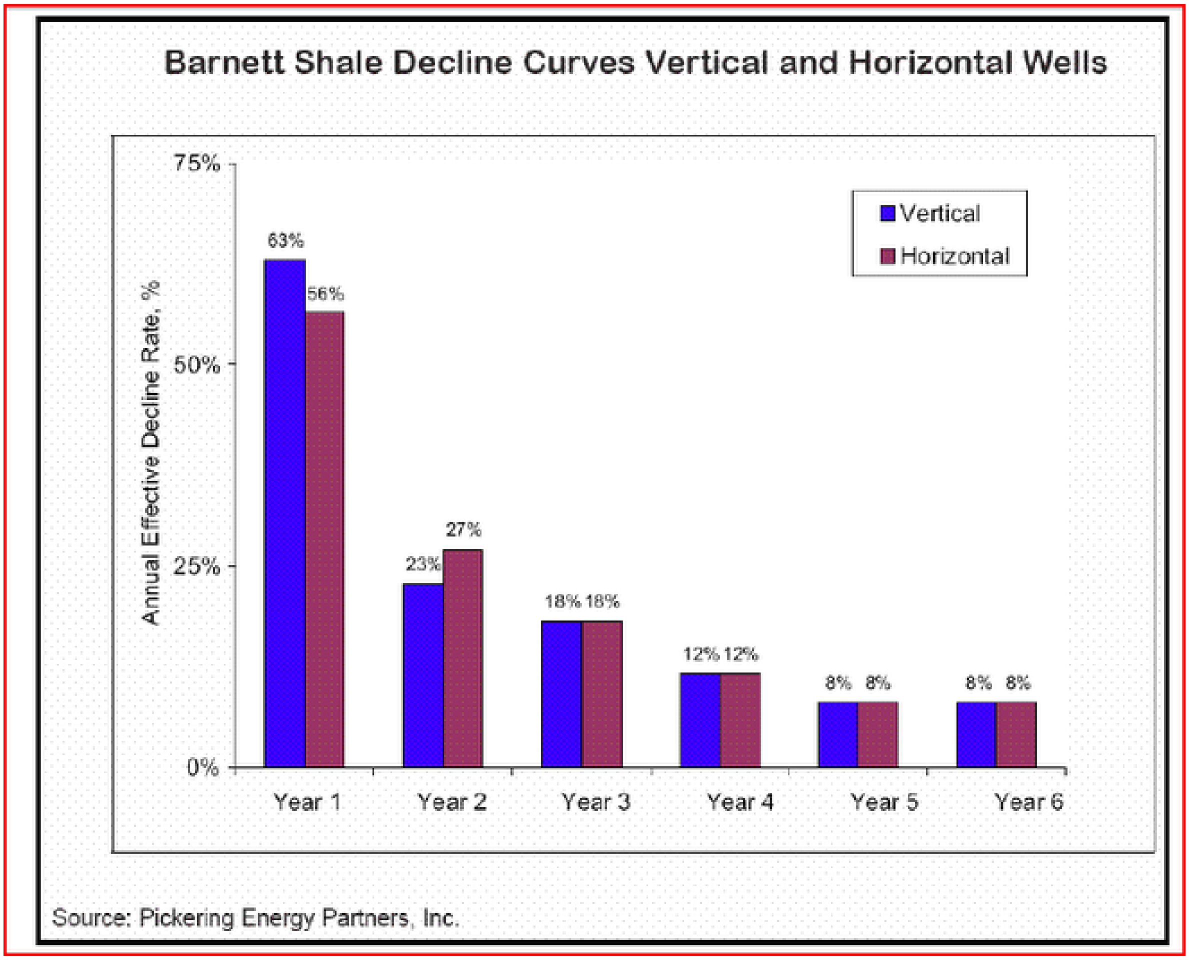


Figure 18. Barnett Shale decline curves vertical and horizontal wells

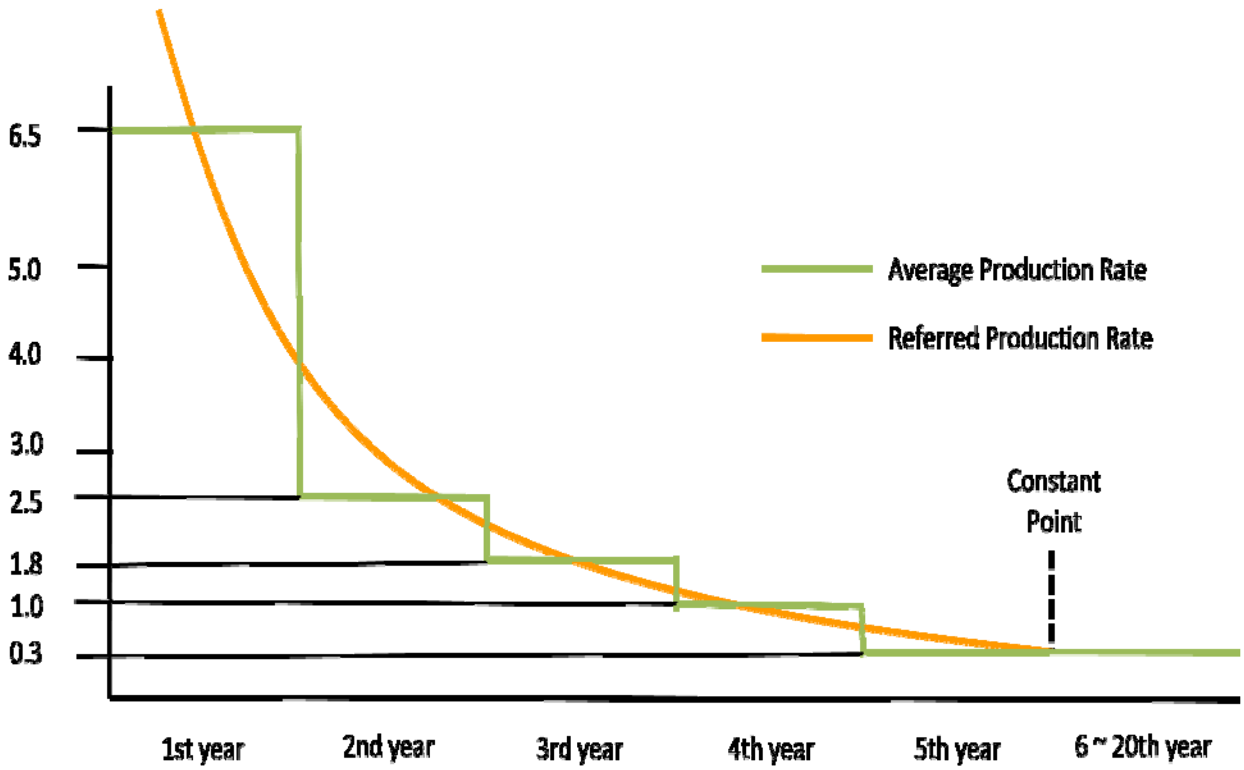


Figure 19. Production rate of a horizontal well (Mmcf/Day)

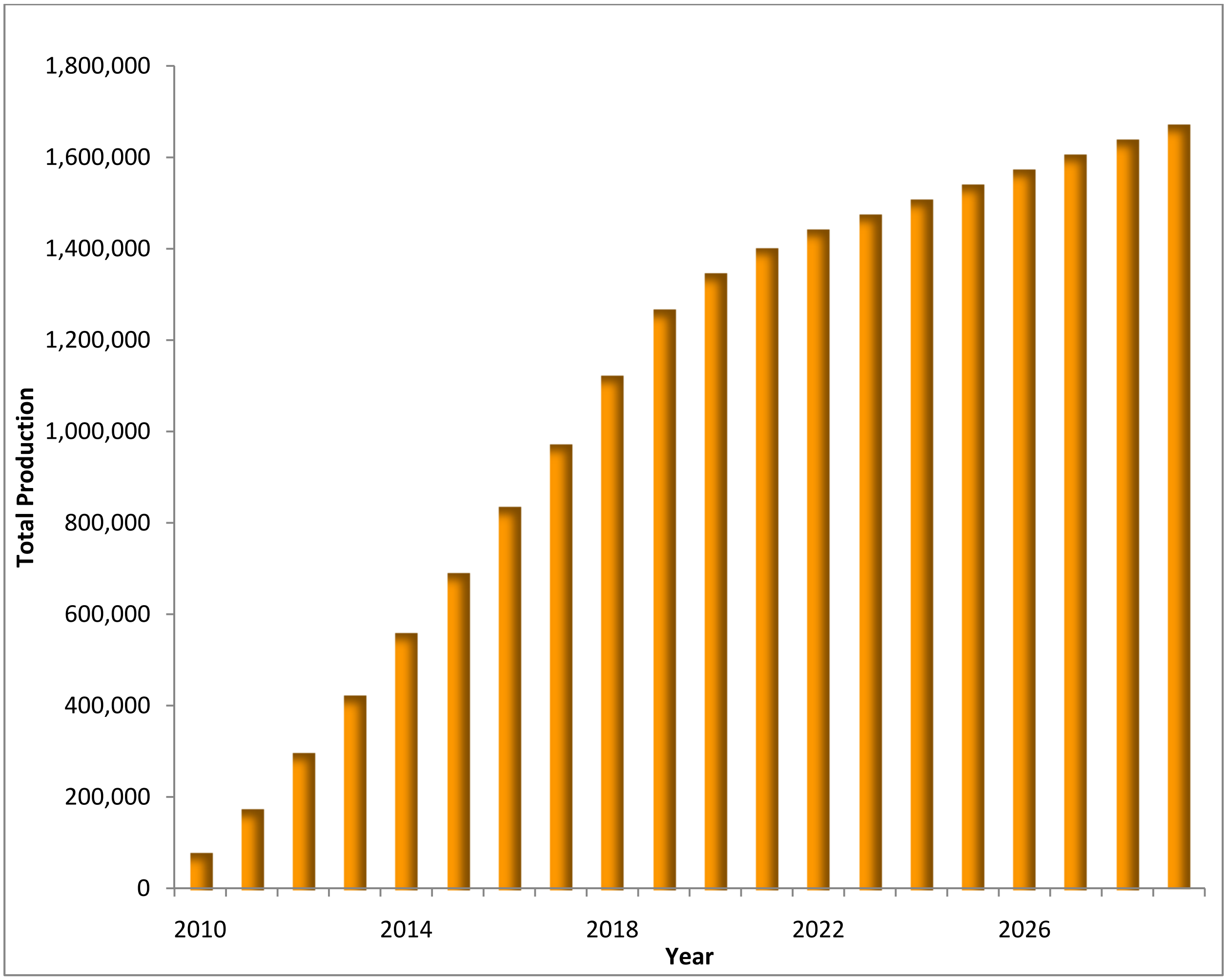


Figure 20.Accumulative Production (Mmcf) in 20 years vs. Year

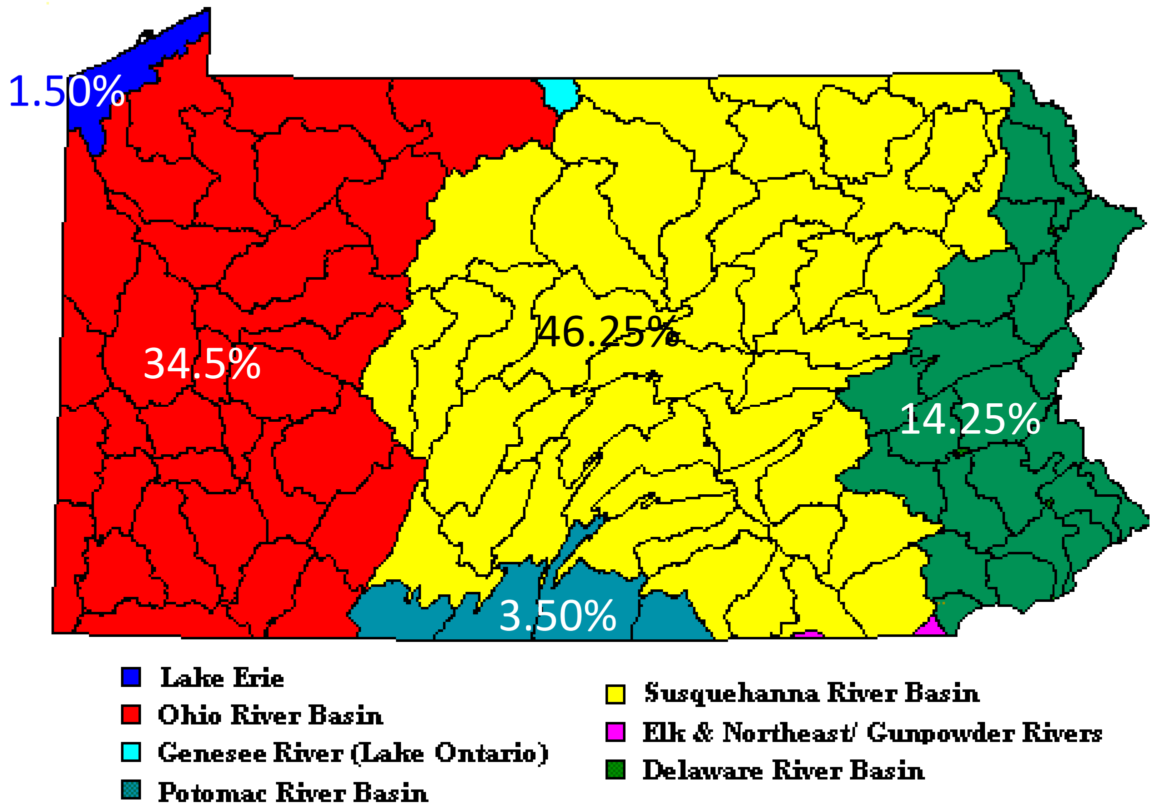


Figure 21. Pennsylvania's River Basins

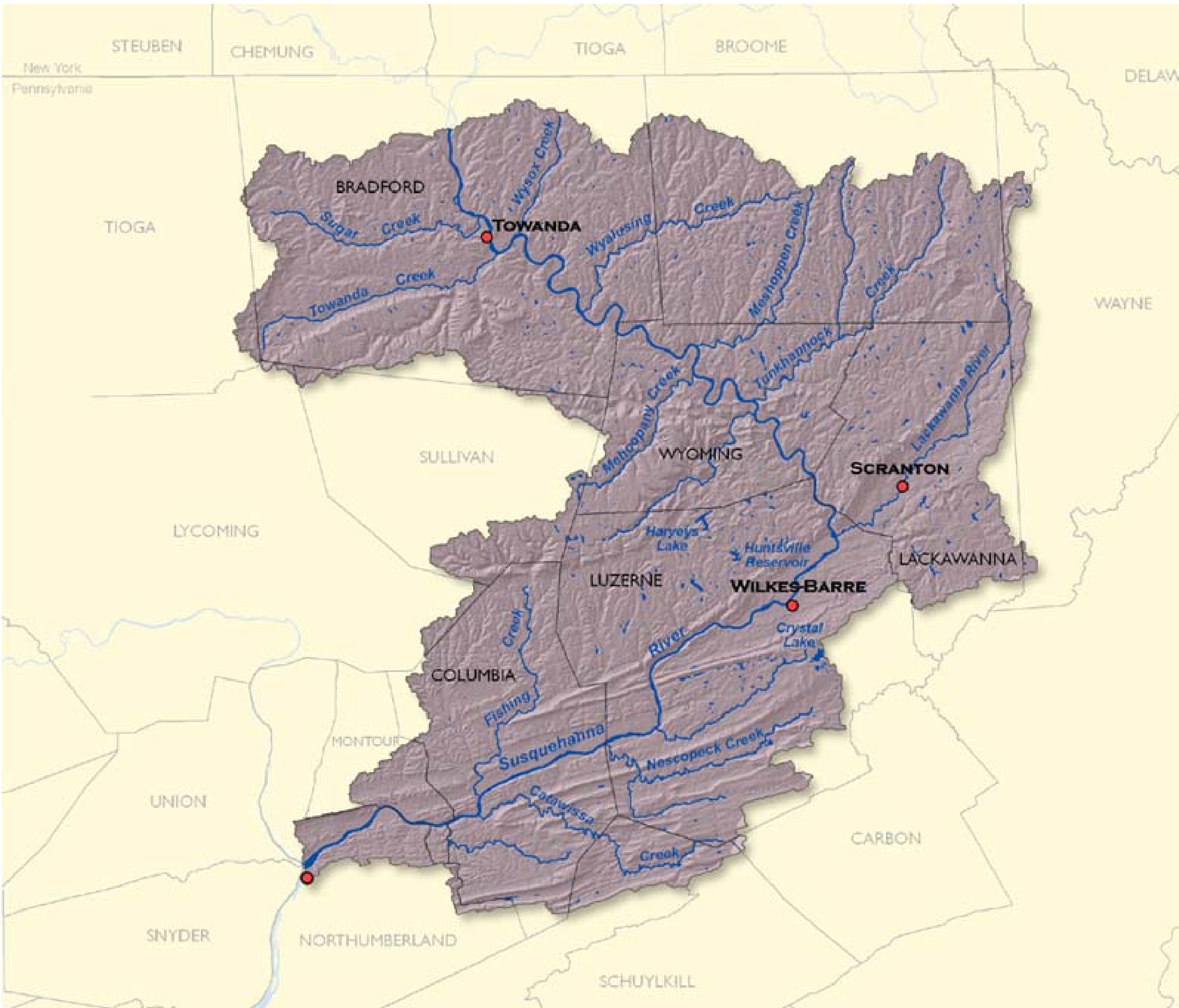
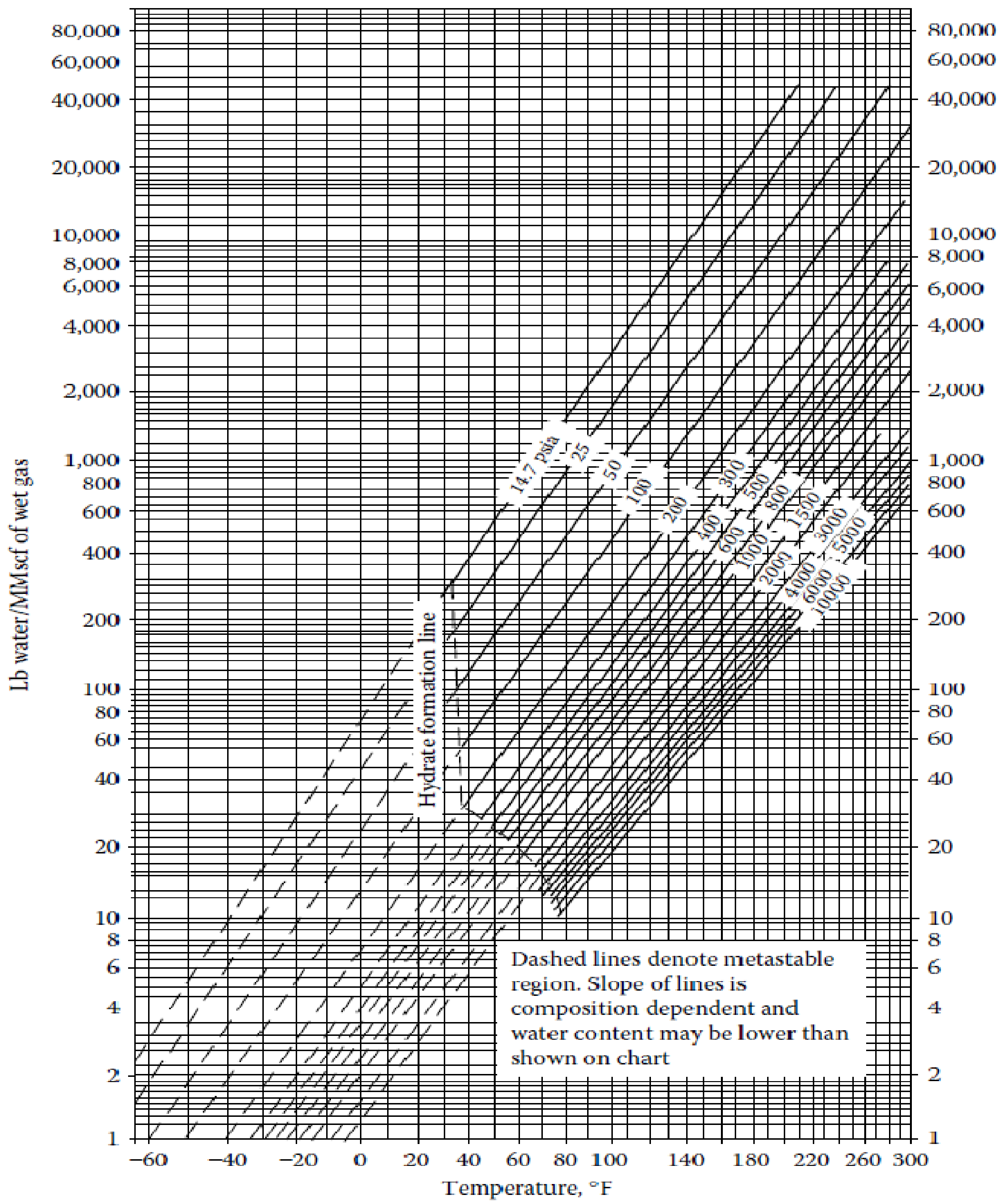


Figure 22. Middle Susquehanna Subbasin

Figure 23. Upper Susquehanna Subbasin



(a)

Figure 24. Water content of hydrocarbon gases as function of temperature and pressure

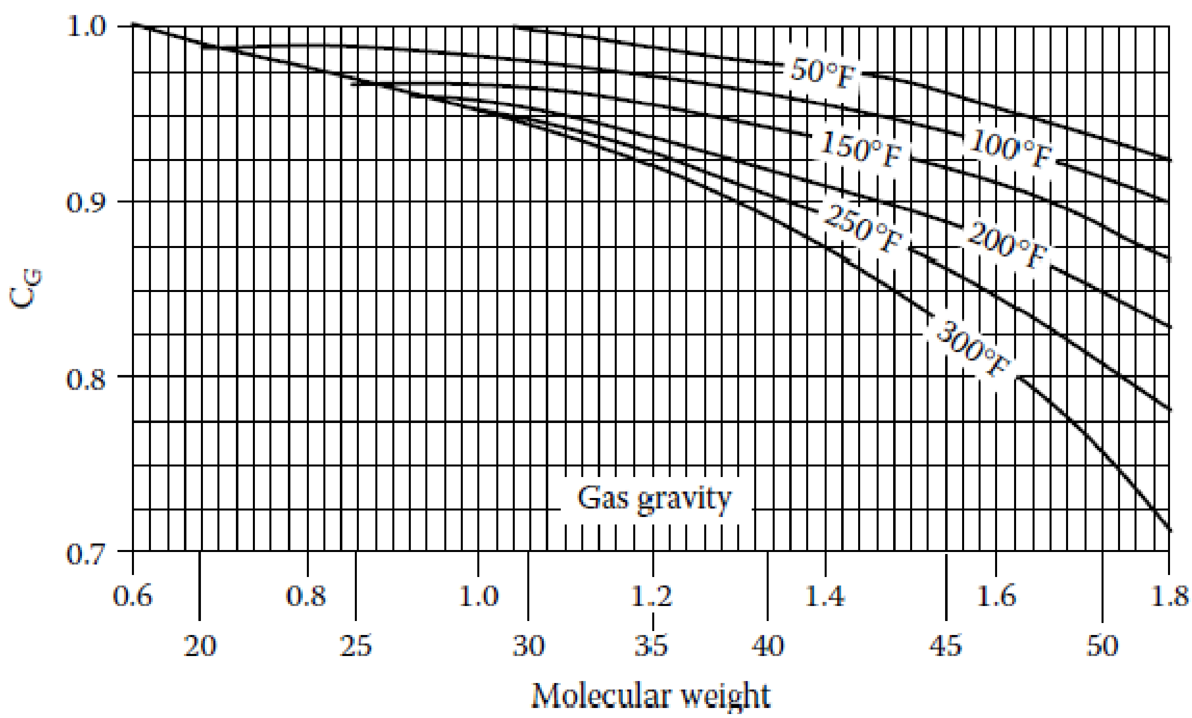


Figure 25. Correction for gas gravity

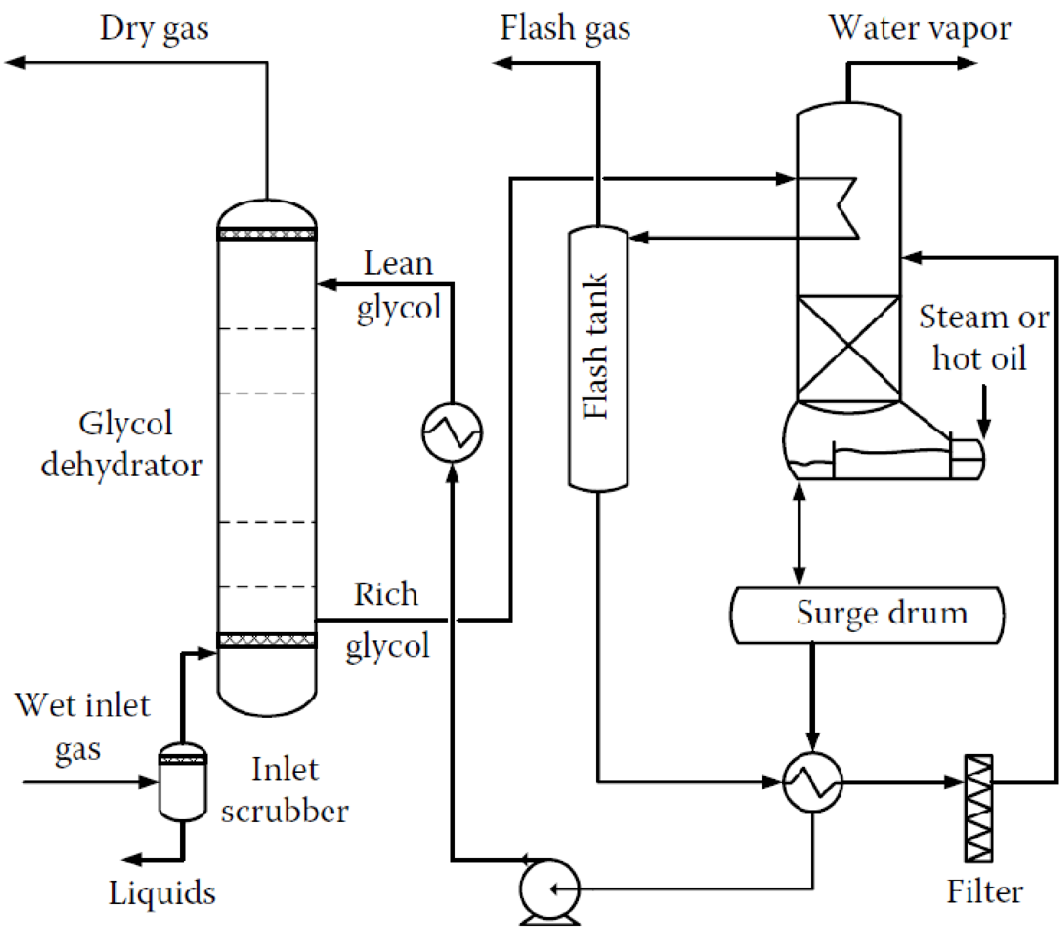


Figure 26. Schematic of typical glycol dehydrator unit

Figure 27. Pictorial representation of SWOT analysis

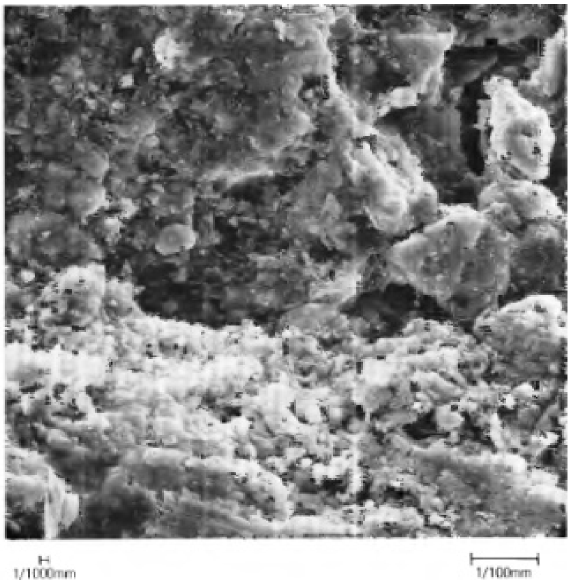


Figure 28.Visible pits and pores, Marcellus Shale from Allegany County, N.Y. **(128)**

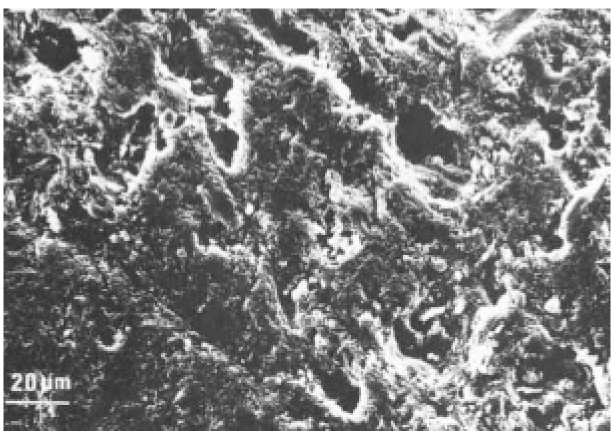


Figure 29. Morphology of shale grain before pyrolysis **(129)**

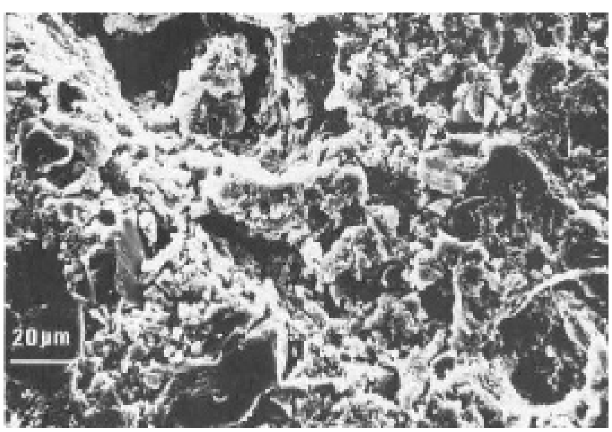


Figure 30.Morphology of shale grain surface after Pyrolysis **(129)**

APPENDIX B: TABLES

Table 1. Drainage areas of wells from various sources

Sources	Vertical Well Area (acres)	Horizontal Well Area (acres)
Independent Oil & Gas Association (110)	-	200-640
Tompkins County Water Resources Council (130)	-	640
Susquehanna River Basin Commission (131)	40	200-400
Upper Monongahela River Association (132)	40	640
W. Virginia Surface Owner's Rights Organization (133)	40	160
Chesapeake Energy (24)	160	-
XTO Energy (134)– West Virginia	80–100	-
Atlas Energy – southwestern PA	40	-

Table 2. Fracturing fluid additives, main compounds and common uses

Additive Type	Main Compound	Common Use of Main Compound
Acid	Hydrochloric acid or muriatic acid	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Cold sterilant in health care industry
Breaker	Sodium Chloride	Food preservative
Corrosion inhibitor	N,n-dimethyl formamide	Used as a crystallization medium in Pharmaceutical Industry
Friction Reducer	Petroleum distillate	Cosmetics including hair, make-up, nail and skin products
Gel	Guar gum or hydroxyethyl cellulose	Thickener used in cosmetics, sauces and salad dressings.
Iron Control	2-hydroxy-1,2,3-propanetricabo xylic acid	Citric Acid it is used to remove lime deposits Lemon Juice ~7% Citric Acid
Oxygen scavenger	Ammonium bisulfite	Used in cosmetics
Proppant	Silica, quartz sand	Play Sand
Scale inhibitor	Ethylene glycol	Automotive antifreeze and de-icing agent

(Source: Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, 2008)

Table 3. Production Rates per day in Marcellus Shale by companies

Company Name	Well type	Production Rate (MMcf./Day)	Region
Range Resources (135)	Horizontal	Aver. 7.3 (Max. 24.5)	No info.
CNX Gas Corporation (136)	Horizontal	Aver. 6.5	Greene County, PA
Cabot Oil & Gas Corporation (137)	Horizontal	Aver. 13	Northeastern PA
Atlas Energy Resources (138)	Vertical	Aver. 3.6	Fayette County, PA
Rex Energy Corporation (139)	Vertical	Aver. 0.5 (Max. 1.2)	Westmoreland County

Table 4. Costs of completion of vertical and horizontal well in Marcellus Shale

Company Name	Vertical	Horizontal	Description
Range Resources (140)	$0.81 million	$3-$5 million	Marcellus Shale
Cabot Oil & Gas Corporation (141)	$1.2-1.5 million	$2.6-2.9 million	7,200-8,925 feet in PA
Atlas Energy Resources (142)	$1.3 million	$4 million	Marcellus Shale
Equitable Resources (143)	$1.3 million	$3-4 million	Doddridge County
Terry Engelder (PSU) (144)	$0.8 million	$3 million	6,000-7,000 feet in PA
Gary Lash (Fredonia St. College) (145)	$0.75 million	$3.5 million	PA in Marcellus Shale

Table 5. Consumption natural gas in Pennsylvania in 2007 (113)

Consumer	Consumption (MMcf)	Percentage
Residential	231,257	32.65
Commercial	145,841	20.59
Industrial	190,524	26.90
Electric Power	140,222	19.80
Vehicle fuel	342	0.05

Table 6. Activities in counties in Pennsylvania

Name of County	Activities
Lycoming County	Chief Oil and Gas LLC has drilled two wells in Mifflin Township and one in Watson Township — and, in late 2007 was preparing to drill a well in Penn Township. The company plans to drill three more wells early in 2008 (146). In April, 2008, Range Resources stated that it had drilled three wells in Lycoming County and was in the midst of its fourth (147)
Fayette County	Atlas Energy Resources has drilled 58 wells as of May, 2008. Atlas Energy Resources has about 250,000 acres under lease in southwestern Pennsylvania, which includes Fayette, Greene, Westmoreland and part of Washington counties (148)
Washington County	Range Resources has drilled five horizontal wells into the Marcellus shale (149)
Susquehanna County	Turm Oil of Butler, recently drilled a well in Rush Township (150).Cabot Oil has drilled a well in Dimock Township (150). As of March, 2008, Southwestern Energy Company subsidiary SEPCO has drilled one exploratory well in Herrick Township. This is expected to be followed by two more exploratory wells in the County
Greene County	There have been number of wells that have shown Marcellus gas. The question is whether or not it can be made commercial (148)
Clearfield County	Mid-East Gas Inc./M.M. & V Energy LLC. has partnered with Denver-based Rimrock Energy LLC, to begin deep well and horizontal drilling in this area. At the present time they are drilling test wells (151)
Indiana County	Dominion Exploration & Production expects to drill 140 natural gas wells in Pennsylvania in 2008, and 25 to 30 of those will be in Indiana County. Penneco Oil Co. ordinarily drills five to 10 new wells a year in Indiana County, and that number could approach 15 in 2008 (149). It is not clear how many of the Dominion or Penneco wells will be drilled into the Marcellus shale formation
Allegheny County	Resources, Inc. has leased land in this county

Table 7. Lease cost for the counties for a 7 year period (17)

County Name	Lease Cost ($/acre)
Lycoming	2500
Fayette	1150
Washington	2800
Susquehanna	2500
Greene	3000
Clearfield	2500
Indiana	2500
Allegheny	1525

Table 8. Consumption of natural gas in MMcf for the year 2007 for different sectors

Consumption	PA	NY	NJ
Residential	231,257	396,685	228,051
Commercial	145,841	289,551	168,778
Industrial	190,524	79,512	63,075
Electric Power	140,222	408,260	157,375

Table 9. Price of Natural Gas delivered to consumers in 2007 (Dollars per Thousand Cubic Feet)

States	City gate price	Residential price	Commercial price	Industrial price
PA	9.35	14.66	12.77	10.64
NJ	10.21	14.48	12.1	9.63
NY	8.61	15.49	11.72	11.33

Table 10. Gas price $ per MCF in previous years

Year	U.S. Natural	KT	MD	NJ	NY	NC	OK	OR	PA
2000	4.62	4.93	5.36	5.34	4.67	5.09	3.91	3.87	5.09
2001	5.72	6.32	6.78	6.41	4.71	6.74	6.48	5.04	6.68
2002	4.12	4.45	4.94	5.33	3.9	4.52	4.24	5.25	5.2
2003	5.85	6.11	6.87	7.16	5.73	6.79	5.87	5.19	6.48
2004	6.65	7.28	7.77	7.82	6.36	7.45	6.56	5.86	7.56
2005	8.67	9.69	9.99	9.7	8.22	10.11	7.9	7.12	9.98
2006	8.61	9.07	10.62	10.85	9.22	9.42	9.13	8.1	10.3
2007	8.12	8.22	9.24	10.21	8.61	8.55	8.14	8.14	9.35
2008	9.15		10.2	11.39		10.46	8.4	8.82	10.39

Table 11. Cost of transportation and storage of our gas

Gas Transportation Rates	
Monthly Customer Charge	$1,000
Supply Reservation Charge	$0.37 times first 5,000 Mcf of monthly portion of nominated annual contract, and $0.33 times the balance of its monthly portion.
Transportation Charge	$0.33 per Mcf for first 60,000 Mcf, and $0.36 per Mcf for the balance transported for the year.
Monthly Balancing	The Trunkline owners (in this case Columbia Gas) will retain customer's excess deliveries up to 5% of customer's consumption in any particular month. The pipeline owner will, at its discretion also retain additional volumes and charge customer $0.15 per Mcf for the service.
Gas Storage Rates	
Administrative fee	$350 per month
Storage charge	Up to $1.70 per Mcf
Fuel injection charge	1.9% of the storage charge for injection and 1.7% for withdrawal
Monthly deliverability charge	$5.828 per Mcf
Monthly capacity charge	$1.095 per Mcf

Table 12. Original data for 8 counties in PA

Criterion/County	Lycoming	Fayette	Washington	Susquehanna	Greene	Clearfield	Indiana	Allegheny	Ideal Value
TOC	4	5	3	5	4	3	3	3	5
CAI	4	4.75	4	5	4.5	4.75	4.75	4.2	5
Ro%	2.75	2.25	1.5	2.75	1.5	1.75	2	1.75	2.75
Thickness	175	100	50	225	75	100	100	100	225
Depth	7000	7000	6500	5500	7500	8000	8000	6500	5500
Water Availability	1	3	3	1	4	2	3	2	1
Pipeline Proximity	3	3	3	1	2	2	2	3	1
Terrain	2	3	3	1	2	2	3	3	1
Road	2	2	2	2	3	2	2	1	1
Lease Cost	2500	500	3100	2500	3000	2500	2500	3000	500
Fracture porosity	3	2	4	1	2	3	2	4	1
Market Distance	2	4	4	1	4	3	3	4	1

Table 13. Normalized data

Criterion/County	Lycoming	Fayette	Washington	Susquehanna	Greene	Clearfield	Indiana	Allegheny	Ideal Value
TOC	0.800	1.000	0.600	1.000	0.800	0.600	0.600	0.600	1
CAI	0.800	0.950	0.800	1.000	0.900	0.950	0.950	0.840	1
Ro%	1.000	0.818	0.545	1.000	0.545	0.636	0.727	0.636	1
Thickness	0.778	0.444	0.222	1.000	0.333	0.444	0.444	0.444	1
Depth	0.786	0.786	0.846	1.000	0.733	0.688	0.688	0.846	1
Water Availability	1.000	0.333	0.333	1.000	0.250	0.500	0.333	0.500	1
Pipelines Proximity	0.333	0.333	0.333	1.000	0.500	0.500	0.500	0.333	1
Terrain	0.500	0.333	0.333	1.000	0.500	0.500	0.333	0.333	1
Road	0.500	0.500	0.500	0.500	0.333	0.500	0.500	1.000	1
Lease cost Rohan	0.200	1.000	0.161	0.200	0.167	0.200	0.200	0.167	1
Fracture porosity	0.333	0.500	0.250	1.000	0.500	0.333	0.500	0.250	1
Market Distance	0.500	0.250	0.250	1.000	0.250	0.333	0.333	0.250	1

Table 14. L1 Metric results

Criterion/County	Lycoming	Fayette	Washington	Susquehanna	Greene	Clearfield	Indiana	Allegheny
TOC	0.200	0.000	0.400	0.000	0.200	0.400	0.400	0.400
CAI	0.200	0.050	0.200	0.000	0.100	0.050	0.050	0.160
Ro%	0.000	0.182	0.455	0.000	0.455	0.364	0.273	0.364
Thickness	0.222	0.556	0.778	0.000	0.667	0.556	0.556	0.556
Depth	0.214	0.214	0.154	0.000	0.267	0.313	0.313	0.154
Water Availability	0.000	0.667	0.667	0.000	0.750	0.500	0.667	0.500
Pipelines Proximity	0.667	0.667	0.667	0.000	0.500	0.500	0.500	0.667
Terrain	0.500	0.667	0.667	0.000	0.500	0.500	0.667	0.667
Road	0.500	0.500	0.500	0.500	0.667	0.500	0.500	0.000
Lease Cost	0.800	0.000	0.839	0.800	0.833	0.800	0.800	0.833
Fracture Porosity	0.667	0.500	0.750	0.000	0.500	0.667	0.500	0.750
Market Distance	0.500	0.750	0.750	0.000	0.750	0.667	0.667	0.750
Column Sum	4.470	4.752	6.825	1.300	6.188	5.815	5.891	5.800
Ranking	2	3	8	1	7	5	6	4

Table 15. Pair-wise Comparison between the 12 criteria

C1>C2	C2=C3	C3>C4	C4<C5	C5>C6	C6>C7	C7>C8	C8>C9	C9<C10	C10>C11	C11<C12
C1>C3	C2>C4	C3>C5	C4<C6	C5>C7	C6>C8	C7>C9	C8>C10	C9<C11	C10<C12	
C1>C4	C2>C5	C3>C6	C4<C7	C5>C8	C6>C9	C7>C10	C8>C11	C9<12		
C1>C5	C2>C6	C3>C7	C4<C8	C5>C9	C6>C10	C7>C11	C8<C12			
C1>C6	C2>C7	C3>C8	C4<C9	C5>C10	C6>C11	C7<C12				
C1>C7	C2>C8	C3>C9	C4<C10	C5>C11	C6>C12					
C1>C8	C2>C9	C3>C10	C4<C11	C5>C12						
C1>C9	C2>C10	C3>C11	C4<C12							
C1>C10	C2>C11	C3>C12								
C1>C11	C2>C12									
C1>C12										

Table 16. Pair-wise comparison matrix

	C1	C2	C3	C4	C5	C6	C7	C8	C9	C10	C11	C12	Row Sum	Weight
C1	1	1	1	1	1	1	1	1	1	1	1	1	12	0.1519
C2	0	1	1	1	1	1	1	1	1	1	1	1	11	0.1392
C3	0	1	1	1	1	1	1	1	1	1	1	1	11	0.1392
C4	0	0	0	1	0	0	0	0	0	0	0	0	1	0.0127
C5	0	0	0	1	1	1	1	1	1	1	1	1	9	0.1139
C6	0	0	0	1	0	1	1	1	1	1	1	1	8	0.1013
C7	0	0	0	1	0	0	1	1	1	1	1	0	6	0.0759
C8	0	0	0	1	0	0	0	1	1	1	1	0	5	0.0633
C9	0	0	0	1	0	0	0	0	1	0	0	0	2	0.0253
C10	0	0	0	1	0	0	0	0	1	1	1	0	4	0.0506
C11	0	0	0	1	0	0	0	0	1	0	1	0	3	0.0380
C12	0	0	0	1	0	0	1	1	1	1	1	1	7	0.0886
													79	

Table 17. Score and ranking from pair-wise comparison/borda count method

	Lycoming	Fayette	Washington	Susquehanna	Greene	Clearfield	Indiana	Allegheny
Score	0.734	0.671	0.497	0.957	0.554	0.581	0.573	0.566
Rank	2	3	8	1	7	4	5	6

Table 18. Comparison of county rankings using L1 metrics and pair-wise comparison/ borda count

Ranking method	Lycoming	Fayette	Washington	Susquehanna	Greene	Clearfield	Indiana	Allegheny
L_1 Metric	2	3	8	1	7	5	6	4
Pair-wise comparison	2	3	8	1	7	4	5	6

Table 19.List of Drilling Fluid Additives (2)

Function	Additive	Usage
Weighting	Barite	This material is used to increase the density of fluid
Corrosion Inhibitor	N,n-dimethyl formamide (79)	To protect pipes and other metallic components from acidic compounds met in the formation
Dispersants	Iron Lignosulfonates	Break up solid clusters into small particles
Flocculants	Acrylic polymers	To group together suspended particles
Biocide	Glutaraldehyde (79)	To kill bacteria and help reduce the souring of fluid
Acid	Hydrochloric Acid (79)	To defoam and emulsify the drilling fluid.

Table 20. Total production rates by companies

Company Name	Well Type	Total Production Rate (MMcf/day)	Days	Location
Range Resources (135)	8 Horizontals	1,032 MMcf	30	PA
CNX Gas Corporation (152)	1 Horizontal	195 MMcf	30	Northeastern PA
Cabot Oil & Gas Corporation (137)	1 Horizontal	Aver. 13 MMcf	-	Northeastern PA
Atlas Energy Resources (138)	13 Verticals	132 MMcf	60	Southwestern PA
Equitable Resources (153)	1 Horizontal	57 MMcf	30	PA

Table 21. Production rate of wells which are made per month (MMcf/Month)

	1st year	2nd year	3rd year	4th year	5th year	6th year
1st well	2372.5	912.5	657	365	109.5	109.5
2nd well	2171	1036.5	678.7	389.8	131.2	109.5
3rd well	1989	1148.5	698.3	412.2	150.8	109.5
4th well	1787.5	1272.5	720	437	172.5	109.5
5th well	1592.5	1392.5	741	461	193.5	109.5
6th well	1391	1516.5	762.7	485.8	215.2	109.5
7th well	1196	1636.5	783.7	509.8	236.2	109.5
8th well	994.5	1760.5	805.4	534.6	257.9	109.5
9th well	793	1884.5	827.1	559.4	279.6	109.5
10th well	598	2004.5	848.1	583.4	300.6	109.5
11th well	396.5	2128.5	869.8	608.2	322.3	109.5
12th well	201.5	2248.5	890.8	632.2	343.3	109.5

Table 22. Total production rate calculation

* Production Rate

	1st year	2nd year	3rd year	4th year	5th year	6th year	7th year	8th year	9th year	10th year
Group1	11862.5	4562.5	3285	1825	547.5	547.5	547.5	547.5	547.5	547.5
Group2	10855	5182.5	3393.5	1949	656	547.5	547.5	547.5	547.5	547.5
Group3	9945	5742.5	3491.5	2061	754	547.5	547.5	547.5	547.5	547.5
Group4	8937.5	6362.5	3600	2185	862.5	547.5	547.5	547.5	547.5	547.5
Group5	7962.5	6962.5	3705	2305	967.5	547.5	547.5	547.5	547.5	547.5
Group6	6955	7582.5	3813.5	2429	1076	547.5	547.5	547.5	547.5	547.5
Group7	5980	8182.5	3918.5	2549	1181	547.5	547.5	547.5	547.5	547.5
Group8	4972.5	8802.5	4027	2673	1289.5	547.5	547.5	547.5	547.5	547.5
Group9	3965	9422.5	4135.5	2797	1398	547.5	547.5	547.5	547.5	547.5
Group10	2990	10022.5	4240.5	2917	1503	547.5	547.5	547.5	547.5	547.5
Group11	1982.5	10642.5	4349	3041	1611.5	547.5	547.5	547.5	547.5	547.5
Group12	1007.5	11242.5	4454	3161	1716.5	547.5	547.5	547.5	547.5	547.5
		Group1	11862.5	4562.5	3285	1825	547.5	547.5	547.5	547.5
		Group2	10855	5182.5	3393.5	1949	656	547.5	547.5	547.5
		Group3	9945	5742.5	3491.5	2061	754	547.5	547.5	547.5
		Group4	8937.5	6362.5	3600	2185	862.5	547.5	547.5	547.5
		Group5	7962.5	6962.5	3705	2305	967.5	547.5	547.5	547.5
		Group6	6955	7582.5	3813.5	2429	1076	547.5	547.5	547.5
		Group7	5980	8182.5	3918.5	2549	1181	547.5	547.5	547.5
		Group8	4972.5	8802.5	4027	2673	1289.5	547.5	547.5	547.5
		Group9	3965	9422.5	4135.5	2797	1398	547.5	547.5	547.5
		Group10	2990	10022.5	4240.5	2917	1503	547.5	547.5	547.5
		Group11	1982.5	10642.5	4349	3041	1611.5	547.5	547.5	547.5
		Group12	1007.5	11242.5	4454	3161	1716.5	547.5	547.5	547.5
				Group1	11862.5	4562.5	3285	1825	547.5	547.5
				Group2	10855	5182.5	3393.5	1949	656	547.5
				Group3	9945	5742.5	3491.5	2061	754	547.5
				Group4	8937.5	6362.5	3600	2185	862.5	547.5
				Group5	7962.5	6962.5	3705	2305	967.5	547.5
				Group6	6955	7582.5	3813.5	2429	1076	547.5
				Group7	5980	8182.5	3918.5	2549	1181	547.5
				Group8	4972.5	8802.5	4027	2673	1289.5	547.5
				Group9	3965	9422.5	4135.5	2797	1398	547.5
				Group10	2990	10022.5	4240.5	2917	1503	547.5
				Group11	1982.5	10642.5	4349	3041	1611.5	547.5
				Group12	1007.5	11242.5	4454	3161	1716.5	547.5
						Group1	11862.5	4562.5	3285	1825
						Group2	10855	5182.5	3393.5	1949
						Group3	9945	5742.5	3491.5	2061
						Group4	8937.5	6362.5	3600	2185
						Group5	7962.5	6962.5	3705	2305
						Group6	6955	7582.5	3813.5	2429
						Group7	5980	8182.5	3918.5	2549
						Group8	4972.5	8802.5	4027	2673
						Group9	3965	9422.5	4135.5	2797
						Group10	2990	10022.5	4240.5	2917
						Group11	1982.5	10642.5	4349	3041
						Group12	1007.5	11242.5	4454	3161
								Group1	11862.5	4562.5
								Group2	10855	5182.5
								Group3	9945	5742.5
								Group4	8937.5	6362.5
								Group5	7962.5	6962.5
								Group6	6955	7582.5
								Group7	5980	8182.5
								Group8	4972.5	8802.5
								Group9	3965	9422.5
								Group10	2990	10022.5
								Group11	1982.5	10642.5
								Group12	1007.5	11242.5
Total P	77415	94710	123828	124602	137391	131172	143961	137742	150531	144312
Accumulate	77415	172125	295953	420555	557946	689118	833079	970821	1121352	1265664
P/day rate	212.096	259.479	339.255	341.375	376.414	359.375	394.414	377.375	412.414	395.375

* Each production rates are following Graph1.
* Each group has 5 wells (Five wells are made simoultaneously using 5 rigs.)
* Jan.,Mar.,May,Jul.,Aug.,Oct.,Dec. are 31 days and Apr., Jun., Sep., Nov. are 30 days and Feb. is 28 days.
* Unit is "Mmcf"

11th year	12th year	13th year	14th year	15th year	16th year	17th year	18th year	19th year	20th year	Total
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30295
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30248.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30206.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30160
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30115
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30068.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	30023.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29977
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29930.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29885.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29839
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29794
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29200
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29153.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29111.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29065
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	29020
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28973.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28928.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28882
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28835.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28790.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28744
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28699
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28105
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28058.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	28016.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27970
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27925
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27878.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27833.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27787
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27740.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27695.5
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27649
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27604
547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	27010
656	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26963.5
754	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26921.5
862.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26875
967.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26830
1076	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26783.5
1181	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26738.5
1289.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26692
1398	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26645.5
1503	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26600.5
1611.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26554
1716.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	26509
3285	1825	547.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25915
3393.5	1949	656	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25868.5
3491.5	2061	754	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25826.5
3600	2185	862.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25780
3705	2305	967.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25735
3813.5	2429	1076	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25688.5
3918.5	2549	1181	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25643.5
4027	2673	1289.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25597
4135.5	2797	1398	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25550.5
4240.5	2917	1503	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25505.5
4349	3041	1611.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25459
4454	3161	1716.5	547.5	547.5	547.5	547.5	547.5	547.5	547.5	25414
79686	56172	39843	32850	32850	32850	32850	32850	32850	32850	1671315
1345350	1401522	1441365	1474215	1507065	1539915	1572765	1605615	1638465	1671315	1503015
218.318	153.896	109.159	90	90	90	90	90	90	90	228.947

Table 23. Total land usage (acre)

Company Name	1st Year	3rd year	5th year	7th year	9th year	5 year total
Total well number	60 wells	60 wells	60 wells	60 wells	60 wells	300 wells
Estimated Land Usage	9,000	9,000	9,000	9,000	9,000	45,000
Real Land Usage	10,000	10,000	10,000	10,000	10,000	50,000

Table 24. Total production rate (Mmcf/Day)

	1st year	2nd year	3rd year	4th year	5th year
Year Total	77,415	94,710	123,828	124,602	137,391
Daily P/rate (Mmcf)	212.096	259.480	339.255	341.375	376.414
	6th year	7th year	8th year	9th year	10th year
	131,172	143,961	137,742	150,531	144,312
	359.375	394.474	377.375	412.414	395.375
	11th Year	12thyear	13th year	14th year	15th year
	79,686	56,172	39,843	32,850	32,850
	218.318	153.896	109.159	90	90
20 Year Total	16th Year	17thyear	18th year	19th year	20th year
1,671,315	32,850	32,850	32,850	32,850	32,850
228.947	90	90	90	90	90

Table 25. Total cost of making wells (Million dollars)

	1st Year	3rd year	5th year	7th year	9th year	5 year total
Total well number	60 wells	60 wells	60 wells	60 wells	60 wells	300 wells
Total Cost	240	240	240	240	240	1200

Table 26. Pennsylvania Basin Overview **(117)**

Basin Name	Basin Size (sq. miles)	Area in PA (sq. miles)	Percent of Basin in PA	Percent of PA in Basin
Susquehanna	27,510	20,960	76%	46.25%
Ohio	164,000	15,614	10%	34.50%
Delaware	13,539	6,466	48%	14.25%
Potomac	14,670	1,584	11%	3.50%
Great Lakes	295,000	610	--	1.50%
Elk & Northeast	330	64	19%	--
Gunpowder	455	11	2%	--

Table 27. Evaporation rate for Susquehanna River Basin

Month	Inches of Evaporation
January	0
February	0
March	0
April	3.0
May	4.9
June	5.4
July	5.8
August	4.9
September	3.6
October	2.4
November	0
December	0

Table 28. National Ambient Air Quality Standards

	Primary Standards		Secondary Standards	
Pollutant	Level	Averaging Time	Level	Averaging Time
Carbon Monoxide	9 ppm (10 mg/m^3)	8-hour(1)	None	
	35 ppm (40 mg/m^3)	1-hour(1)		
Sulfur Dioxide	0.03 ppm	Annual (Arithmetic Mean)	0.5ppm (1,300 ug/m3)	3-hour
	0.14 ppm	24-hour(1)		
Nitrogen Dioxide	0.053 ppm (100 ug/m^3)	Annual (Arithmetic Mean)	Same as Primary	
Lead	0.15 ug/m^3	Rolling 3-Month Average	Same as Primary	
	1.5 ug/m^3	Quarterly Average	Same as Primary	
Particulate Matter(PM10)	150 ug/m^3	24-hour	Same as Primary	
Particulate Matter(PM2.5)	15.0 ug/m^3	Annual (Arithmetic Mean)	Same as Primary	
	35 ug/m^3	24-hour	Same as Primary	
Ozone	0.075 ppm (2008 std)	8-hour	Same as Primary	
	0.08 ppm (1997 std)	8-hour	Same as Primary	
	0.12 ppm	1-hour (Applies only in limited areas)	Same as Primary	

Table ES-1. Pennsylvania Climate Roadmap: Policy Recommendation (88)

Energy Supply
Expand the AEPS to 25% by 2025 and Require Tier 2 Non-Renewables to be Carbon-Neutral
Add a Dedicated “Tier 3” Energy Efficiency Component to AEPS
Create a Public Benefit Fund for Electric Utilities
Implement a Portfolio of Energy Efficiency Policies to Complement AEPS Tier 3
Enact New and Updated Energy Efficiency Standard for Electrical Equipment and Appliances
Reduce CH4 and other GHG form Coal/Oil/Gas Operations
Residential/Commercial/Industrial(RCI)
Create a Public Benefit Fund for Natural Gas Utilities
Enact New and Updated Efficiency Standards for Natural Gas Equipment
Create Incentives for Efficient Building Design
Encourage Upgrades/Retrofits of Existing Residential and Commercial Buildings
Expand Use of Biomass Energy
Use Biofuel In Heating Oil
Promote Power Generation Using Methane from Wastewater Facilities
Provide Better Energy Efficiency and GHG Information to Consumers
Transportation and Land Use
Establish Renewable Fuel Standard of 25% by 2025
Expand Alternative Fuels Incentive Grant Program
Adopt Fuel Efficiency Standard for Replacement Tires
Pilot a Program of Nitrogen-Inflated Tires on Fleet Vehicles
Implement Smart Growth and Smart Transportation Initiatives of the Pennsylvania Transportation Funding and
Promote Smart Growth Development of Communities
Expand Incentives for Alternatives to single Occupancy Vehicles
Encourage “Pay-As-You-Drive”(PAYD) Insurance
Ban Idling by Heavy-Duty Vehicles
Increase Use of Intermodal Freight Transportation
Agriculture
Promote Carbon Sequestration in Soil
Promote Consumption of Locally Grown Agricultural Products
Promote Improved and Integrated Animal Waste Management Systems
Forestry
Protect, Restore, and Regenerate Existing Forests
Establish New Forests
Enhance Use and Lifetime of Durable Wood Products
Geological Sequestration
Develop Protocols for Sitting and sequestration
Develop Pilot Projects to Demonstrate Geologic Sequestration
Shape National, Economy-Wide Cap-and-Trade Legislation, Likely to become Law
Actively Shape the National “Climate Registry” and Help Establish a National Reporting System for Emissions
Pursue the Integration of Federal, State, and Local Efforts on Climate Change

Table 29. Sensitivity analysis for various parameters (as NPV)

	Gas Price	Drilling Cost	Royalty	Administrative Cost	Lease Cost
Initial Value	8.47-10.87	$4.0 million	12.5%	10% + 5% /yr	1500 $/acre
+40%	($2,603,746,197)	($311,205,231)	($269,271,953)	($378,938,421)	($565,409,592)
+20%	($1,602,067,458)	($455,796,975)	($434,830,336)	($489,663,570)	($582,899,156)
-20%	($-401,290,018)	($744,980,464)	($765,947,103)	($711,113,868)	($617,878,283)
-40%	($-1,402,968,757)	($889,572,208)	($931,505,486)	($821,839,018)	($635,367,847)

Table 30. Sensitivity analysis for various parameters (as %NPV change)

	Gas Price	Drilling Cost	Royalty	Administrative Cost	Lease Cost
Initial Value	8.47-10.87	$4.0 million	12.5%	10% + 5% /yr	1500 $/acre
+40%	333.68%	-48.17%	-55.15%	-36.88%	-5.83%
+20%	166.84%	-24.08%	-27.58%	-18.44%	-2.91%
-20%	-166.84%	24.08%	27.58%	18.44%	2.91%
-40%	-333.68%	48.17%	55.15%	36.88%	5.83%

APPENDIX C: CALCULATIONS

APPENDIX C-1: DRILLING PERMIT FEE

Vertical Drilling:

$$C_V = \begin{cases} 200 & D \leq 1500 \\ 250 & 1500 < D \leq 2000 \\ 250 + 50\left(\dfrac{\mathrm{D} - 2000}{500}\right) & 2000 < D \leq 5000 \\ 550 + 100\left(\dfrac{\mathrm{D} - 5000}{500}\right) & D \geq 5000 \end{cases}$$

$D = 6000 \qquad C_V = 550 + 100\left(\frac{\mathrm{D}-5000}{500}\right) = 550 + 100\left(\frac{6000-5000}{500}\right) = 750$

Horizontal Drilling:

$$C_H = \begin{cases} 900 & L \leq 1500 \\ 900 + 100\left(\dfrac{\mathrm{L} - 1500}{500}\right) & L > 1500 \end{cases}$$

$L = 4000 \qquad C_H = 900 + 100\left(\frac{4000-1500}{500}\right) = 1400$

Total Cost of Drilling permit:

$C_{T=}\ C_{V+}\ C_H = 750+1400=2150$

APPENDIX C-2: WELL COMPLETION

Note: Values are assumed closest to the actual by estimating based on literature review and API design standards.

Cement:

Cement has to have an equivalent mud weight between 0.58 psi/ft which is the formation pressure (worst case scenario) and the fracture pressure 0.93 psi/ft.

Based on this density of mud will be, $\rho_{mud} = \frac{0.58}{0.052} = 12\ lbs/gal$

Considering cement to consist of cement, water and Bentonite we perform the calculations so that mud density will be equal to 12 lbs/gal.

All calculations below are per sack of cement

Contents	Weight (lbs)	1/ρ (gal/lbs)	Volume (gal)
Cement	94	0.0382	3.59
Bentonite	X	0.0453	0.0453*X
Water for Cement	43.33	0.12	5.2
Water for Bentonite	5.75*X	0.12	0.691*X

Bentonite requires 1.3 gallons per 2% bentonite used.

12 = $\frac{\Sigma W}{\Sigma V}$ = $\frac{94+X+43.33+5.75*X}{3.59+0.0453*X+5.2+\ 0.691*X}$

Solving for X we get,

X=15.27 lbs.

So now a sack of cement will have the following components,

Contents	Weight (lbs)	1/ρ (gal/lbs)	Volume (gal)
Cement	94	0.0382	3.59
Bentonite	15.27	0.0453	0.691

Water for Cement	43.33	0.12	5.2
Water for Bentonite	87.8	0.12	10.55

Amount of cement that we needed for each well,

= volume of cement needed for conductor casing + volume of cement needed for surface casing + volume of cement needed for production casing

$=(\frac{\Pi}{4}*(36^2-30^2)*300)+\left(\frac{\Pi}{4}*(15^2-13^2)*1700\right)+(\frac{\Pi}{4}*(6^2-5^2)*8000)$

= 237,190 ft^3

=1,774,304 gallons

Therefore the total number of sacks of cement needed for each well,

$=\frac{1774304}{3.59+.691+5.2+10.55}$

=88,577

Therefore it would require 88,577 sacks of cement required for each well.

Production Casing:

Depth: 6000 ft

Lateral Length: 4000 ft

Factors of Safety: N_c= 1.8, N_a=2.0, N_j=4.0, N_i=1.5

Pressure gradient: 0.58 psi/ft (worst case scenario)

Maximum burst pressure

P_b= 6000*0.58*1.5= 5220 psi

Maximum collapse pressure

P_c= 0.052*12*6000*1.8= 6739 psi

The greatest pressure that the casing will have to withstand is the pressure generated during hydraulic fracturing.

P_f= 7500*1.5= 11250 psi

The cheapest type of casing that can withstand this pressure is 5" N-80 with a nominal weight of 21.4 lb/ft with buttress thread regular coupling higher grade.

To check if it can be used for the entire length it is required to check its joint and axial strength.

Joint strength,

$P_{J-D}= P_J/N_J= 537000/4= 134250$ psi

Max length= 134250/21.4= 6273 ft

Axial strength

$=P_Y/N_A=501000/2= 250200$ psi

Max length= 250200/21.4= 11705 ft

From this it is clear we can use this casing for the entire length including the lateral.

Fracture Design:

To estimate the fracture dimensions we use the K-G-D method

$$\overline{w} = 0.29 * [(q_i * \mu * (1-\nu) * x_f^2)/(G * h_f)]^{1/4} * (\frac{\pi}{4})$$

Fracture half length and height is based on a thickness of 200 ft and a drainage radius of 150 acres. The fracture half length was designed such that there would maximum stress shadowing effects between fracture treatments of adjacent wells.

q_i= 90 bpm

x_f= 500 ft

h_f= 100 ft

μ= 100 cp

ν= 0.3

G= $2 * 10^6$

$\overline{w}$ = 0.38 inches

This gives average fracture width obtained with the following parameters.

APPENDIX C-3: PLANT CAPACITY CALCULATION

Design basis

100MMSCFD = 2.8 million m^3 of gas at 800psi and 100 ^oF

Gas flow rate=117917 m^3/hr

From (***Figure 24***) we can determine the water content by connecting the pressure and temperature and reading the water content. The reading gave Wc= 70lb/MMscf, this is not the actual water content so we need to make some correction.

(***Figure 25***) provide corrections for gas gravity. C_G= 0.98 and multiplication gives

$$W = 70 * 0.98 = 68.6\ lb/MMscf$$

Therefore the water content for the 2.8 million m^3 of gas at 800psi and 100 ^oF is 69lb/MMscf= 1105mg/m^3= 0.001105Kg/m^3

Gas specification at 4lb/MMscf or 64mg $H2O/m^3$

W_{in}= 1105mg/ m^3

W_{out}= 64mg/ m^3

$$Water\ removal\ efficiency = \frac{(\mathrm{W_{in}} - \mathrm{W_{out}})}{\mathrm{W_{in}}} = \frac{(1105 - 64)}{1105} = 94\%$$

$$Water\ removal\ rate = 0.001105\frac{Kg}{m^3} \times 2830000\frac{m^3}{D} \times \frac{D}{24hr} = 130.3\ Kg/hr$$

The water mass flow rate is 130.3Kg/hr

Determination mass flow rate of lean and rich TEG

The TEG circulating rate commonly used are between 2 to 5 gal TEG/lb H2O removed. We assumed a circulation rate of 3gallons TEG/lb water removed or 25L TEG/Kg H2O. From the "water removal vs. TEG circulation rate" graph (figure C-1), this efficiency can be achieved with a 99.5% strength TEG circulating at 25 L TEG/kg H2O.

With a circulation rate of 0.0 25 m^3 TEG/kg H2O it was possible to calculate the amount of TEG used per hour:

$$TEG\ circulation\ rate = 130.3\frac{Kg}{hr} \times 0.025\frac{m^3}{Kg\ H20} = 3.26\ m^3/hr$$

For the calculation of the mass flow rate of TEG, the density of lean TEG at 38 ^{o}C was needed and this equation (154) below was used to calculate the density of glycol.

$\rho = -0.783T + 1140$

$$\rho = -0.783 \times 38 + 1140 = 1110Kg/m^3$$

$$TEG\ mass\ flow\ rate = \rho\dot{V} = 1110\frac{Kg}{m^3} \times 3.26\frac{m^3}{hr} = 3618\ Kg/hr$$

The flow of pure TEG was calculated using the purity of the TEG found to be 99.5%

$$mass\ flow\ rate\ of\ pure\ TEG = 0.995 \times 3618\frac{Kg}{hr} = 3599\ Kg/hr$$

$$mass\ flow\ rate\ water\ in\ lean\ TEG = 0.005 \times 3618\frac{Kg}{hr} = 15.84\ Kg/hr$$

Rich TEG mass flow rate

$$mass\ flow\ rate\ of\ rich\ TEG = lean\ TEG + \ water = 3599 + 130.3 = 3730Kg/hr$$

$$Rich\ TEG\ wt\% = \frac{3599}{3730 + 15.84} \times 100 = 96\%$$

Volumetric flow rate of rich TEG

$$\dot{V}_{rich} = \frac{\dot{m}}{\rho} = \frac{3730}{1110} = 3.36m^3/hr$$

Determination of the reboiler duty

For a water removal flow rate of 25LTEG/Kg H2O, the glycol circulation rate calculated previously is 3.26 m^3/h or 861.77 gal/h

From table C- 1 q=862 Btu/gal TEG for a 3 gal TEg per water removed (155).

So

$$q = \frac{862\ Btu}{gal} \times \frac{861.77\ gal}{hr} = 743MBtu/hr$$

So a it is better to use a reboiler 150% higher to allow for startup heat load, (155) therefore the reboiler duty is around:

$q = \ 1114\ MBtu/hr$= 2.74 MJ/h

Calculation of exchangers' duty

The specific heat for lean TEG was calculated using the following equation (154)

$$C_p\ = 4.186 \times (0.00122T + 0.471)$$

And for the rich TEG

$$C_p\ = m * T + c$$

$$m = 0.000073 * TEGc - 0.00219$$

$$c = -0.03534 * TEGc + 5.5056$$

TEGc calculated earlier=96 %

$$C_p\ = 0.004818 * T + 2.11296$$

The temperature used to calculate the heat exchangers duty was assumed for a good design of the plant.

T_1= 38 ^oC $C_p\ = 2.29KJ/(Kg.C)$

T_2=93 ^oC $C_p\ = 2.56KJ/(Kg.C)$

$$C_{p\ ,Av} = 2.43KJ/(Kg.C)$$

So for the glycol preheater

$$q = mC_{p\,,Av} \times (T_2 - T_1)$$

$$q = 3730\frac{Kg}{hr} \times 2.43\frac{KJ}{Kg.C}(93 - 38) = 499MJ/hr$$

The rich glycol preheater duty is 499 MJ/hr

Glycol /glycol exchanger

T_1= 93 °C $C_p = 2.56KJ/(Kg.C)$

T_2=148 °C $C_p = 2.82\ KJ/(Kg.C)$

$$C_{p\,,Av} = 2.69KJ/(Kg.C)$$

$$q = 3730\frac{Kg}{hr} \times 2.69\frac{KJ}{Kg.C}(148 - 93) = 552MJ/hr$$

The heat for the glycol/glycol exchanger is 552 MJ/hr

Gas /glycol exchanger

Specific heat for lean TEG calculated using

$$C_p = 4.186 \times (0.00122T + 0.471)$$

T_1= 69 °C $C_p = 2.32\ KJ/(Kg.C)$

T_2=43 °C $C_p = 2.19\ KJ/(Kg.C)$

$$C_{p\,,Av} = 2.26\ KJ/(Kg.C)$$

$$q = 3618\frac{Kg}{hr} \times 2.26\frac{KJ}{Kg.C}(43 - 69) = -213MJ/hr$$

Diameter still column

For a 25-mm pall ring, the diameter of the still column is calculated using the following equation (154)

$$d = 210 * (q_{TEG})^{0.5}$$

q_{TEG} is the TEG circulation rate = 3.26 m3/hr

$d = 210 * (3.26)^{0.5} = 379mm$

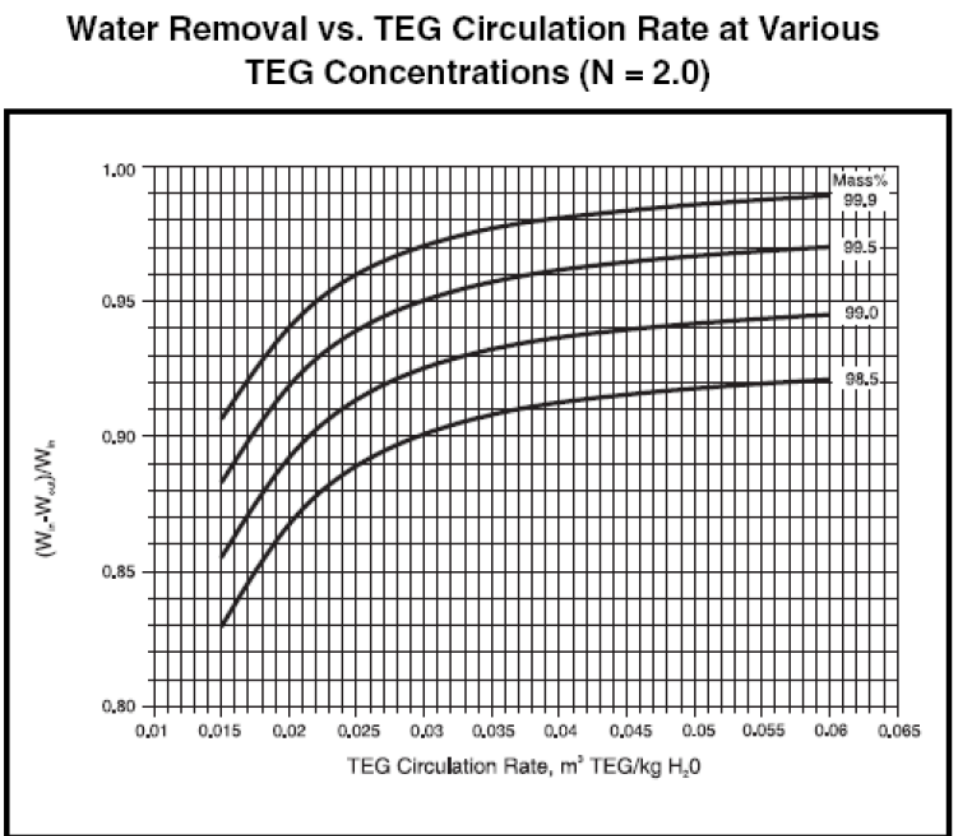


Figure C. Water removal efficiency vs TEG circulation rate

Table C-1 Approximate Reboiler Heat Duty

Design Gallons of Glycol Circulated /lb H2O Removed	Reboiler Heat Duty Btu/Gal of Glycol Circulated
2.0	1066
2.5	943
3.0	862
3.5	805
4.0	762
4.5	729
5.0	701

Size at 150% of above to allow for start-up, increased circulation, fouling

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