ANALYSIS AND APPLICATIONS OF NATURAL GAS MICRO-GRIDS

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Abstract

The introduction of the Marcellus Shale play to the Pennsylvania natural gas industry has had various effects throughout the sector. Some large pipeline operators, in anticipation of increased demand for pipe access, have already or are considering significantly increasing the required pressure to input gas into their pipelines and the tariff they charge per unit of gas to gain access. These changes could represent a considerable increase in compression and overall costs for operators of shallow, low pressure wells that are nearing the end of their project life. In other cases, producers are concerned with being able to secure pipeline access at all. An option instead of using distribution pipelines is to create an alternative delivery architecture and directly supply the end users with a “Micro-Grid.”

The economic viability of a Micro-Grid was analyzed through two case studies in the Pennsylvania region by creating a model of the cash flows from the projects. It was determined that when pipeline access is available and infrastructure already exists to deliver to the distribution line, a Micro-Grid is not the best economic option. It is, however, a viable option for a group of wells without existing infrastructure available to deliver to the pipeline transmission system or that cannot secure access to a distribution pipeline.
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1. Introduction

The Micro-Grid is not a new concept in the world of electric power. It can help to relieve stress on the larger electricity grid by localizing generation, transmission and loads (McGowan 1992). The same concept, however, has not been considered extensively in natural gas distribution. Before tremendous advances in transmission and storage technology, producers were not able to almost all natural gas producers delivered their product over short distances directly to the end user. The influx of shale gas in the US has put a strain on the natural gas transmission network, increasing costs and causing securing of pipeline access to be more difficult. Applying the concept of the electric Micro-Grid to natural gas transmission is a potential solution for these transport problems and others with similar impacts.

The following pages will give a brief background on natural gas, including a brief history of natural gas in the United States, the importance and usage of natural gas today, and the introduction and impact of the Marcellus Shale. Once the problem is discussed more in depth, the two case studies of DuBois and Penn State will be introduced as well as the economic model. The paper will conclude with the results of the model applied to the case studies and the conclusions learned from both studies.
2. Background Information

2.1 Advantages and Disadvantages of Natural Gas

Natural gas is a hydrocarbon consisting mostly of methane that today is used for electric generation, heating, and industrial purposes in addition to a variety of other uses. Natural gas is often found in the same geological structures as oil. It is often reported that natural gas was discarded as waste—either burned up or simply allowed to escape—in order to access the oil considered more valuable or abandoned completely if oil was not found (DOE 2011; Castaneda, 2004).

Many proponents of natural gas today still believe that the energy source is undervalued. In a Deloitte Center for Energy Solutions Report, author Dr. Joseph Stanislaw denounces the US for its “marginalization of natural gas” claiming the fuel is “is desperately sought after by nearly every country, yet somehow the U.S. considers it a lesser fuel” (Stanislaw 2009). It is well known that natural gas burns the cleanest of all fossil fuels. Even after the EPA increased its estimates of natural gas methanes emissions, a study found that US natural gas-fired electricity generation still emitted 47% less greenhouse gases than plants powered by coal (M2 PressWIRE 2011). In her paper, Margaret van Egteren makes a case for the use of natural in electricity generation, citing not only its cleanliness compared to other fuels, but also natural gas fired plant’s efficiency and lower probability to have siting delays (van Egteren 1993). The Australian government’s commodity research branch, ABARE, adds to that that natural gas fired plants have less capital costs and can more quickly react to changes in electricity demand (Platts 2002).

There are, however, many people who are wary of natural gas. Early on in the industry, undetected leakages proved to be dangerous, resulting in explosions and fatalities. This danger has been chiefly eliminated by the odorization of natural gas. Leakages are still a source of environmental concern. A study completed in the early 1990s concluded that a leakage rate of 3% would offset the environmental
advantages that natural gas otherwise causes (Gorrie 1990). The most common argument against
natural gas today generally revolves around shale plays and hydraulic fracturing, or “fracking.”
Opponents to fracking argue that the process contaminates groundwater with both methane and the
chemicals used in the process (Issues in Science and Technology 2011). Additionally, they are opposed to
the large amount of water used in fracking. The industry denies these accusations, claiming that there
are no proven cases of this happening and that any cases of water contamination are due to producers
breaking state and federal regulations (Peltier 2011).

2.1 A Brief History of Natural Gas in United States

Written reports of people observing natural gas date back many centuries. French explorers
reported witnessing Native Americans lighting the gas as early as 1626 (Speight 2007). In the 1700s,
George Washington and Thomas Jefferson also wrote of witnessing natural gas springs while on
expeditions. Still more accounts included observing hunters use the ignited gas to cook meat (Castaneda
2004). Although the utilization of natural gas dates back to ancient times, its widespread use was
difficult because of the inability to transport or store the gas.

In 1821, William Hart of Fredonia, New York was the first to intentionally drill a well for natural gas
in the US (DOE 2011). Shortly afterwards, he succeeded at developing a system to deliver the gas to
local homes for lighting as well as the harbor’s lighthouse. For many years, this remained the model;
local wells delivering gas to nearby customers for the purposes of lighting (Castaneda 2004). This held
ture until the 1880s, when the concept of electric lighting began to gain some momentum. At the same
time, possibly as a result of the efforts of natural gas producers to keep a market for their product,
natural gas using appliances-including stoves, water tanks, and the Bunsen burner- began to appear
(Speight 2007).
Through the late 1800s, insufficient transmission and storage technology continued to be the chief impediment of the natural gas industry. An early 20-mile wooden pipeline in 1870 failed as a result of leakage and the inability to prevent erosion (Speight 2007). Advancements in pipeline technology came into fruition soon enough. The first telescoping pipeline was built in Pittsburgh and inventor Solomon R. Dresser made tremendous developments in pipe coupling technology, making natural gas transmission both safer and more efficient (Castaneda 2004). In the late 1890s, development of the internal combustion engine enabled the addition of compression to pipeline systems, allowing natural gas to be transported over further distances (Speight 2007). By the 1920s, a combination of the introduction of electric welding, stainless steel pipelines, and a new, cheap southwest gas supply as well as an increase in natural gas demand sparked the formation of the new interstate natural gas pipeline industry (Speight 2007; Castaneda 2004).

With the Great Depression came an investigation of the public utilities by the Federal Trade Commission, followed by the introduction of federal regulation of the natural gas industry (Castaneda 2004). One result was the Natural Gas Act of 1938, which gave the Federal Power Commission authority over interstate pipelines (Speight 2007). This era was “the end of a long period of unrestrained and rapid growth in the US public utility industry” (Castaneda 2004). The postwar era brought in a time of tremendous growth in the natural gas industry. This held especially true for the pipeline industry. During the 1950s and 1960s, several thousands of miles of pipelines were built in the US (DOE 2011).

In 1954, the US Supreme Court ruled in what became known as the “Phillips Decision” that the Natural Gas Act also gave jurisdiction over not only natural gas pipeline rates, but also wellhead prices, to the FPC. Due to the vast amount of wellheads throughout the states producing at vastly different production costs, setting “fair and just” rates proved to be a daunting task. Initially, the FPC attempted setting rates on an individual basis, but soon broadened this to regulation by geographical regions and,
by 1974, settled for a national price ceiling (Natural Gas Supply Association 2011). These artificially low prices reduced the incentive to increase exploration and production, while stimulating demand, and resulted in natural gas shortages in the 1960s. The situation was worsened by 1973’s oil embargo which incentivized substituting natural gas of oil consumption (Castaneda 2004).

After a failed attempt to control the customers to whom natural gas companies sold, Congress passed the Natural Gas Policy Act of 1978, making the first steps to deregulation in the natural gas industry. The NGPA sought to homogenize the interstate and intrastate markets, reach a market quantity equilibrium, and arrive at the market price for wellhead prices (Natural Gas Supply Association 2011). Market forces interacted favorably to the new regulation until production was overstimulated. The resulting oversupply and drastic drop in price had a particularly negative impact because the pipeline companies had signed long term contracts at lower prices (Castaneda 2004). Meanwhile, many pipeline customers voiced complaints of having no choice but to buy both their natural gas and its transmission as a bundled service (Natural Gas Supply Association 2011).

Enter FERC Order Numbers 436 and 636, which set up the framework that we are familiar with today. First, in 1985, Order 436 allowed an interstate pipeline company to act as simply a carrier of the natural gas, getting paid only for its services. Prices available to pipeline customers in the spot market were significantly lower than those at which the pipelines sold the gas from their long term contracts, allowing customers to immediately benefit from the change. Order 636, issued in 1992, made Order 436 mandatory, cementing pipeline companies as transmission only entities and no longer buyers and sellers of gas (Natural Gas Supply Association 2011).
2.3 Natural Gas Today

As would be expected, natural gas prices became more volatile as it transformed into a deregulated market, but, as evidenced in Figure 2.3-1, this was particularly true in the last decade. Prices have still not recovered from post-recession lows. On January 20\textsuperscript{th}, natural gas prices fell to a decade low of 2.322 per mmBTU upon the news released by the Department of Energy that the weekly drop in inventory was at 87 billion cubic feet, 38\% of last year’s decline (Strumpf 2012). A week and half before, RBC Capital Markets had reduced its price forecast for 2012 from $4.75 to $4.00, citing an excess supply (Edmonton Journal 2012). A large part of this excess has been due to a mild winter, but it is also attributable to the increase in shale gas production that has been recently added into the supply mix.

*Graphs created from annual EIA wellhead pricing data*

**Figure 2.3-1: US Natural Gas Wellhead Prices: 2000-Present and 1970-Present**

[Graph showing US Natural Gas Wellhead Prices: 2000-Present and 1970-Present]
The EIA released a preview of its Annual Energy Outlook 2012 that significantly decreased its estimates of shale gas resources 2011’s estimate of 862 trillion cubic feet to 482 Tcf (EIA 2012). This is still 482 Tcf more than the shale resources a few years ago when it was considered uneconomical, but a tremendous downgrade from previous estimates. To put these values into perspective, annual US 2010 consumption was approximately 24.1 Tcf per year (Tubb 2011). As seen in Figure 2.3-3 above, the EIA still expects the share of shale gas in the US gas mix to continue to increase in the next 33 years as more shale gas wells come into production. This increasing supply will not necessarily perpetuate the trend of low natural gas prices from the last 3 years as natural gas gains a greater share of an increasing pool of electricity generation (Figure 2.3-3).
In 2011, electric power was the sector with the largest portion of consumption and consisted of 31% of natural gas consumption in the US, as evidenced in Figure 2.3-4. The industrial sector, where natural gas is used for both raw materials and as a heat source, is a close second at 28%. The gas used in the residential and commercial sectors is used chiefly for space and water heating and cooking and make up 19% and 13% of consumption, respectively. Since the development of shale gas, the amount of gas exported from the US has increased significantly. By the year 2016, the EIA expects that the US will become a net exporter of liquefied natural gas (LNG) and an overall exporter of natural gas by 2021 (EIA)
As evidenced in Figure 2.3-5, the price for LNG is more competitive abroad in than in the US. This could mean that becoming a net exporter of LNG could have a significant economic upside if these price discrepancies overcome the transportation costs.


Figure 2.3-5: LNG export prices compared to US import price

2.4 The Marcellus Shale

Figure 2.4-1: Map of Marcellus Shale
The Marcellus Shale spans from Ohio and West Virginia through Maryland and Pennsylvania, to New York, covering approximately 600 square miles. Although its existence has been known since the 1930s, Marcellus did not gain significant interest until 2003. The renewed interest in the play was the result of a perfect storm of improved technology (chiefly horizontal drilling and hydraulic fracturing), a surge in gas prices ($3 to $11 per mmcf between 2002 and 2008), and natural gas becoming a more attractive fuel due to advancements in climate control regulation (New York Affordable Electricity Alliance 2010; Nieto 2008).

![Figure 2.4-2: Average monthly natural gas production (billion cubic feet per day)](http://www.marcellus.psu.edu/resources/PDFs/UticaSummitWeb.pdf)

Just how much gas the play contains is an often debated topic. Early estimates of the gas in the shale ranged from 50 tcf to 1000 tcf. The EIA’s most recent estimate in the Annual Energy Outlook 2012 Early Release Overview reported the shale’s resources at 141 trillion cubic feet, claiming 90% confidence. This was a significant downgrade from the AEO2011’s estimate of 410 tcf. Shale activity in Pennsylvania has still grown at a rapid rate (see Figure 2.4-2). In 2008, there were 196 Marcellus wells drilled, followed by 763 in 2009, 1,386 in 2010 and an estimated 1,592 in 2011 (Marcellus-Shale.us 2011). Production has surged as well. According to Pennsylvania’s Department of Environmental
Protection, in the 18 months from July 2009 until December 2010, 466,327.8 MMcf of Marcellus gas was produced in Pennsylvania. This quantity more than doubled in the following 12 months, with production at 983705.3 MMcf. With this large influx of Marcellus gas in Pennsylvania-and other shale plays in other reasons-some concerns have been raised about attaining pipeline access and increasing pipeline costs.
3. The Problem

The introduction of the Marcellus Shale play to the Pennsylvania natural gas industry has had various effects. In the world of natural gas, pipeline access—i.e. being able to transport product—is key. According to contacts at Little Pine Resources, some large pipeline operators, in anticipation of increased demand for pipe access, have already or are considering significantly increasing the required pressure to input gas into their pipelines. This is not a concern for Marcellus wells that produce at high pressures. This rate hike, however, could represent a considerable increase in compression costs for operators of shallow, low pressure wells that are nearing the end of their project life. Additionally, the influx of pipeline demand makes securing pipeline access more difficult. These obstacles create “stranded gas,” natural gas that cannot be recovered because of either economical or physical reasons.

Stranding natural gas in this way has both private and social costs. Clearly, the inability to produce gas suggests a negative economic impact. Having to abandon a well because of the inability to either afford or access a transmission line would result in the loss of potential profit. A large increase in compression requirements could result in the preemptive abandonment of stripper wells that are reaching the end of their project life. If the pipeline changes are widespread and drive the owners of large groups of such wells to abandonment, it is possible that more wells will not go properly cased for more extended periods of time than otherwise. Improperly plugged wells can leak toxic brine into either the groundwater or the surrounding environment (Suro 1992). Although legislation exists that regulates the plugging of abandoned wells\(^1\), enforcing this legislation would prove to be a daunting task if preemptive well abandonment due to increased compression requirements is a widespread issue among shallow well owners, allowing more wells than usual to go unchecked.

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\(^1\) The Pennsylvania Code, Title 25 Environmental Protection, Part I, Subpart C, Article I, Chapter 78, Subchapter D. Well Drilling, Operation, and Plugging, Sections 78.91-78.98
The remaining gas in a group of wells outside DuBois in Clearfield County, where nearly 2000 wells at the end of their lives would require large compressions costs to input to Columbia Gas Transmission line, may soon become stranded. I will focus on evaluating an alternative delivery architecture—a Micro-Grid delivering directly to an end user—for shallow wells facing this problem. I will apply the model I create to the situation in Clearfield County in addition to another case study involving the Penn State campus and a group of wells owned by NCL Resources. These cases will help me draw general conclusions about the applicability of a Micro-Grid in natural gas distribution.
4. Introduction to the Case Studies

In order to analyze the cost effectiveness of a natural gas Micro-Grid, two case studies were considered. In the following sections I will describe the background information from two case studies, including the proposed Micro-Grid scenario and existing infrastructure or assumptions made about existing infrastructure.

4.1 Clearfield County

Figure 4.1-1: Map of Clearfield County, Pennsylvania

The first case study, Clearfield County, looks at approximately 2000 shallow wells outside of the city of DuBois that are close to the end of their life. These wells produce at low pressure and low volume, especially when compared to nearby Marcellus wells. The two scenarios considered in this case are whether to deliver to the gas to the Columbia Gas Transmission Line or to deliver it directly to a group of customers in the city of DuBois. The existing pipeline infrastructure data was unobtainable, so the case assumed that there were existing gathering systems to deliver gas to certain locations within the large
group of wells, but that the backbone to collect the gas from these various locations as well as the means to deliver this gas to the end user or to the Columbia Line receiver were nonexistent. This assumption of the existing infrastructure is not accurate and not suitable for a business decision, but is appropriate for the purposes of our case study.

Pennsylvania State University Petroleum Engineering PhD candidate, Pichit Vardcharragosad developed a pipeline system for each of the two scenarios. The pipeline networks are shown below in Figure 4.1-2. In the first scenario, delivering the gas directly to the end user, the gas is delivered to Node 12. For the second scenario, delivering gas to the Columbia Pipeline, the gas is delivered to Node 15. In addition to the pipeline network, Vardcharragosad also modeled the gas production and consumption through compression that would be used for the economic model. The wells are estimated to collectively produce a total of 3,300 million cubic feet a year. Vardcharragosad also estimated production quantities assuming a yearly decline rate of 2.95%, derived from historical production statistics.

Maps adapted from Google Earth

Figure 4.1-2: Clearfield County Pipeline Networks
Below is a summary of some significant values from the case. The pipeline miles and diameter and the annual sale gas were determined by Vardcharragosad in his pipeline configuration and analysis of the historical production of the wells. The input pressure is the pressure of the gas at the gathering points. The discharge pressure of the pipeline scenario is the given required input pressure of the Columbia pipeline. The discharge pressure of the end user scenario is an assumed value of what pressure an end user receives natural gas.

### Table 4.1-1 Case Information Summary

<table>
<thead>
<tr>
<th></th>
<th>End User</th>
<th>Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline Miles</td>
<td>43</td>
<td>49</td>
</tr>
<tr>
<td>Pipeline Diameter Range (in)</td>
<td>3-9</td>
<td>3-8</td>
</tr>
<tr>
<td>Annual Sale Gas (MMscf)</td>
<td>3310</td>
<td>3252</td>
</tr>
<tr>
<td>Input Pressure (psia)</td>
<td>24.7</td>
<td>24.7</td>
</tr>
<tr>
<td>Discharge Pressure (psia)</td>
<td>152</td>
<td>1000</td>
</tr>
</tbody>
</table>

#### 4.2 Penn State and NCL Natural Resources

The second case study was inspired by the recent decision of Penn State University to shift much of its coal consumption to natural gas in order to comply with environmental regulations. The study looks at a group of wells north of the university’s location in State College, PA and compares the economic viability of delivering that gas through the Columbia and Dominion pipelines versus building a Micro-Grid directly to Penn State. The Micro-Grid with a Penn State delivery point was also compared to Micro-Grids that followed similar paths, but with closer delivery points (ie not to Penn State).
Figure 4.2-2 displays the proposed pipeline networks for the scenarios. “Pipeline” involves no pipeline construction and uses the existing infrastructure of the Dominion pipeline to deliver the gas to Penn State. This case would only require the capital cost of compressors installed at the NCL Sales Point North. “Penn State” proposes building a Micro-Grid following the right of ways of the Dominion pipeline for a delivery also at Penn State. Pipeline networks “~12” and “~24” explore alternate delivery points 12 and 24 miles closer to the wells, but otherwise on the same path as the Penn State Micro-Grid. These are not comparable in the same respect to the pipeline and Penn State scenarios, but instead serve to determine the effect that the distance of a Micro-Grid has on its economic viability. The estimated production in the first year for these wells would be around 2100 million cubic feet.
Table 4.2-2, like Table 4.1-2 in the previous section, contains some basic summary data of the case and its scenarios.

**Table 4.2-2 Case Information Summary**

<table>
<thead>
<tr>
<th></th>
<th>Pipeline</th>
<th>Penn State</th>
<th>Shortened ~12 miles</th>
<th>Shortened ~24 miles</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pipeline Miles</strong></td>
<td>0</td>
<td>49</td>
<td>27</td>
<td>14.8 miles</td>
</tr>
<tr>
<td><strong>Pipeline Diameter Range (in)</strong></td>
<td>na</td>
<td>3-8</td>
<td>4-8</td>
<td>4-7</td>
</tr>
<tr>
<td><strong>Annual Sale Gas (MMscf)</strong></td>
<td>2082</td>
<td>2100</td>
<td>2102</td>
<td>2105.5</td>
</tr>
<tr>
<td><strong>Input Pressure (psia)</strong></td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td><strong>Discharge Pressure (psia)</strong></td>
<td>1100</td>
<td>150</td>
<td>123</td>
<td>87</td>
</tr>
</tbody>
</table>

Map adapted from Google Earth

**Figure 4.2-2: Penn State and NCL Pipeline Networks**
5. The Economic Model

In order to assess the economic viability of a natural gas Micro-Grid in these cases, I needed a model of the cash flows of the projects. The models required estimates of capital costs, variable costs, revenue, taxes, and depreciation as well as economic and market assumptions. From the model of estimated cash flows, I can calculate the internal rate of return (IRR) and the net present value (NPV), two valuable tools in comparing the economics of projects. I will use these metrics to compare the Micro-Grid versus delivery to the pipeline for each of the case studies under certain assumptions (interest rate, inflation, natural gas price, delivery pressure, distance). I will also vary some of these assumptions in order to observe their effect on the IRR.

5.1 Costs

The model assumed a capital cost expenditure in year zero that accounts for installing the pipeline as well as necessary compression equipment. Pipeline construction costs include costs of materials, labor, right of way, and other miscellaneous expenses such as surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees. The National Energy Technology Lab adapted a University of California regression analysis of pipeline cost data from the Oil and Natural Gas Journal’s Pipeline economics report (Tarka 2010). The analysis resulted in a formula to calculate the cost of each of the four aforementioned factors of construction costs as a function of pipeline length and diameter. NETL’s formulas were adapted to escalate the cost from 2007 dollars to 2012 dollars. The final cost formulas for the pipeline are as follows, where L and D are the length and diameter of a given pipe section:

- Cost of Materials = \((64632 + 1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26960)) \times 1.03^5\)
- Cost of Labor = \((150166 + 1.58 \times L \times (8417 \times D + 7234)) \times 1.03^5\)
- Miscellaneous Costs = \((150166 + 1.58 \times L \times (8417 \times D + 7234)) \times 1.03^5\)
The second aspect of capital costs for the model is cost of building the compressor stations. I estimated compression capital costs, by escalating the dollars from the 2007 pipeline economics report to determine a cost per break horsepower (Smith 2008). From the data in the report, it is apparent that a compressor station benefits from economies of scale. Since the compressor stations in our model are all on the smaller scale (under 2,000 BHP), I excluded the compressor stations over 10,000 BHP for my estimate, using only those that fell between 1,000 and 7,000 BHP. The average cost per BHP of these compressors was approximately $2,600 per BHP, or $3000 per BHP in 2012 dollars. Penn State University Petroleum and Natural Gas Engineering Associate Professor Dr. Luis Ayala confirmed that this was a reasonable estimate for compression station costs.

In addition to the initial capital expenditures, the model incorporated the yearly cost of the different scenarios. In all cases where a pipeline was constructed, an estimate of cost per mile of pipeline was used for the operation and maintenance. This value was estimated to be $50,000 per mile per year using an average of the operating and maintenance cost per mile of 43 pipeline operators in the US (Smith 2008). For cases requiring distribution pipeline access, the tariff of the pipeline accessed was also included. The tariff for accessing the distribution pipeline in either case is assumed to be $0.55 per million cubic feet, an estimated value provided by contacts at Little Pine Resources, who were at one point interested in the group of wells in the Clearfield study.

The third aspect of annual costs for this model is the cost of compression. This cost, however, is treated differently because the compressors are fueled by using some of the natural gas produced. Therefore, the cost of compression is not a direct cost to the producer, but instead the opportunity cost of not selling the fuel gas used for compression. To account for compression costs, fuel needed to

\[
Right of Way Costs = (48037 + 1.2 \times L \times (577 \times D + 29788)) \times 1.03^5
\]

Total Pipeline Costs = Materials + Labor + Miscellaneous + Right of Way
provide the necessary energy for compression was determined and subtracted this from the production gas available to determine the sale gas.

5.2 Revenue, Taxes, and Future Value of Cash Flows

In addition to costs, the model needed to predict sales revenue, taxable income, taxes, and after-tax income. With these values, I would be able to calculate the future value of the cash flow for each year of the project life, values that are necessary to calculate the NPV and the IRR of the projects. I used the following equations to calculate the future value of the cash flow for each year:

\[
\begin{align*}
Revenue_i &= Mcf \times \text{sale gas}_i \times \frac{\$}{\text{Mcf}} \\
\text{Depreciation}_i &= MACRS_i \times \text{capital costs} \\
\text{Taxes}_i &= \text{tax rate} \times \text{taxable income}_i = \text{tax rate} \times (\text{revenue}_i - \text{depreciation}_i - \text{annual costs}_i) \\
\text{Future Value}_i &= \text{revenue}_i - \text{taxes}_i - \text{annual costs}_i
\end{align*}
\]

Revenue in year i is simply units produced multiplied by the price of the unit. In this case, the value of units produced is the sale gas measured in thousand cubic feet (Mcf) and we assumed a long term price outlook of $4 per Mcf. Depreciation in year i, \(d_i\), was calculated using the capital costs outlined in the previous section and the seven year property class of the Modified Accelerated Cost Recovery System (MACRS), the current acceptable tax depreciation system in the United States as outlined by the Internal Revenue Service. The percentages are outlined in Table 5.2-1. To calculate taxes, I assumed a tax rate of 35% applied only to taxable income, revenue less depreciation and the annual costs outlined in the previous section. These values can then be plugged into the future value equation to determine the future value of the net cash flow for each year. Table 5.2-2 summarizes the economic assumptions made for the model.
Table 5.2-1: Depreciation (MACRS)

<table>
<thead>
<tr>
<th>Recovery Year</th>
<th>7-Year Property</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>14.29%</td>
</tr>
<tr>
<td>2</td>
<td>24.49%</td>
</tr>
<tr>
<td>3</td>
<td>17.49%</td>
</tr>
<tr>
<td>4</td>
<td>12.49%</td>
</tr>
<tr>
<td>5</td>
<td>8.93%</td>
</tr>
<tr>
<td>6</td>
<td>8.92%</td>
</tr>
<tr>
<td>7</td>
<td>8.93%</td>
</tr>
<tr>
<td>8</td>
<td>4.46%</td>
</tr>
</tbody>
</table>

Table 5.2-2: Summary of Economic Assumptions

<table>
<thead>
<tr>
<th>Economic Assumptions</th>
<th>Assumption Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount Rate</td>
<td>10%</td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>3%</td>
</tr>
<tr>
<td>Natural Gas Price ($/Mcf)</td>
<td>4</td>
</tr>
<tr>
<td>Income Tax Rate</td>
<td>35%</td>
</tr>
</tbody>
</table>

5.4 Analysis Tools

Two key tools were used in the analysis of the projects: net present value (NPV) and internal rate of return (IRR). Net present value is calculated by discounting each future value to year 0 to take into account the time value of money. Net present value is equal to \( \sum_{i=0}^{T} \frac{FV_i}{(1+(r-inf))^i} \), where \( T \) is the total years of the project, \( FV_i \) is the future value of the net cash flow in year \( i \), \( r \) is the discount rate and \( inf \) is the inflation rate. As stated in the previous section, I have assumed the discount rate to be 10% and the inflation rate to be 3% per year. By discounting all cash flows to the present, projects can be compared on level ground. Essentially, the project with the greatest NPV means it is the superior project. The second tool, IRR is the discount rate at which the net present value of the project is zero. The IRR can be
determined by using the equation \[ 0 = \sum_{i=0}^{T} \frac{FV_i}{(1+IRR)^i} \] to solve for “IRR.” Like NPV, a greater IRR is better, but what is most important is that the IRR passes a hurdle rate. This rate is generally set by the alternative opportunities in which a company can invest its money and usually falls between 10 and 15%. These two metrics were used to compare the delivery to the pipeline and delivery directly to an end user and to see the impact that various variables such as price, distance, and delivery pressure had on the projects.
6. Results and Analysis

6.1 Clearfield County

The model described in the previous chapter was applied to the Clearfield County case study. In the following tables, “Columbia” refers to the scenario involving the sale of gas to the Columbia pipeline and “DuBois” refers to the alternative architecture scenario of building a Micro-Grid directly to end-users. In Tables 6.1-1 and 6.1-2, containing the pipeline and compressor capital costs, it is apparent that under our assumptions about the existing gathering system, the capital costs for the Columbia case have higher capital expenditures than the Micro-Grid. When this result is combined with the knowledge that input into a transmission pipeline like the Columbia Pipeline will require extra compression and tariff costs, one can begin to intuitively predict which scenario will have the more favorable economic result.

Table 6.1-1: Pipeline Costs (in $1000s)

<table>
<thead>
<tr>
<th>Category</th>
<th>Columbia</th>
<th>DuBois</th>
</tr>
</thead>
<tbody>
<tr>
<td>Materials</td>
<td>$5,621</td>
<td>$4,779</td>
</tr>
<tr>
<td>Labor</td>
<td>$25,646</td>
<td>$22,852</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$7,380</td>
<td>$22,852</td>
</tr>
<tr>
<td>Right of Way</td>
<td>$2,966</td>
<td>$2,687</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$41,612</strong></td>
<td><strong>$36,637</strong></td>
</tr>
</tbody>
</table>

Table 6.1-2: Compressor Costs

<table>
<thead>
<tr>
<th>Compression Costs</th>
<th>Columbia</th>
<th>DuBois</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost per BHP</td>
<td>$3,000.00</td>
<td>$3,000.00</td>
</tr>
<tr>
<td>BHP</td>
<td>2556.87</td>
<td>1303.07</td>
</tr>
<tr>
<td><strong>Cost (in $1000s)</strong></td>
<td><strong>$7,671</strong></td>
<td><strong>$3,909</strong></td>
</tr>
</tbody>
</table>

Tables 6.1-3 and 6.1-4 summarize the results of the Micro-Grid and sale to pipeline scenarios, sensitive to project life and constant well production versus a 2.95% decline in well production. It is apparent that the DuBois Micro-Grid scenario is superior to the Columbia Pipeline scenario in each combination of project life and decline rate for both methods of economic evaluation. This is not a surprising result because of the high capital costs associated with the Columbia Pipeline scenario. It is
still interesting to note that all four simulations of the Dubois scenario cleared the commonly used hurdle of 15% IRR, qualifying it as a good investment (under the assumptions made by the case).

**Table 6.1-3: Summary of Net Present Values (in $1000s)**

<table>
<thead>
<tr>
<th></th>
<th>Columbia</th>
<th>DuBois</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 year project life</td>
<td>$11,934</td>
<td>$21,312</td>
</tr>
<tr>
<td>10 yr with 2.95% decline</td>
<td>$ 5,477</td>
<td>$14,856</td>
</tr>
<tr>
<td>15 year project life</td>
<td>$26,196</td>
<td>$36,341</td>
</tr>
<tr>
<td>15 yr with 2.95% decline</td>
<td>$14,545</td>
<td>$24,598</td>
</tr>
</tbody>
</table>

**Table 6.1-4: Summary of Internal Rates of Return**

<table>
<thead>
<tr>
<th></th>
<th>Columbia</th>
<th>DuBois</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 year project life</td>
<td>12.37%</td>
<td>18.06%</td>
</tr>
<tr>
<td>10 yr with 2.95% decline</td>
<td>9.68%</td>
<td>15.41%</td>
</tr>
<tr>
<td>15 year project life</td>
<td>15.52%</td>
<td>20.64%</td>
</tr>
<tr>
<td>15 yr with 2.95% decline</td>
<td>12.46%</td>
<td>17.69%</td>
</tr>
</tbody>
</table>

Table 6.1-5 contains the prices at which each of the projects would clear the 15% IRR hurdle.

Assuming all else constant, if the head of project believes the prevailing and future market price of natural gas to surpass one of these values, then the project is a good investment.

**Table 6.1-5: Hurdle-Clearing Prices (for models with 2.95% gas production decline)**

<table>
<thead>
<tr>
<th></th>
<th>Columbia</th>
<th>DuBois</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 yrs</td>
<td>$ 4.83</td>
<td>$ 3.94</td>
</tr>
<tr>
<td>15 yrs</td>
<td>$ 4.41</td>
<td>$ 3.61</td>
</tr>
</tbody>
</table>

**Sensitivity Analysis**

Uncertainty in some variables can affect the economic outcome of the projects. For this reason, it is important to analyze the effects changing the assumptions we have made. One factor that certainly has an effect on the economic outcome is the price at which the producer can sell the natural gas. The NPV and IRR analysis displayed above assumed a price of $4 per MCF. Figure 6.1-1 shows how the IRRs for delivery to the Columbia Pipeline at 10 and 15 year project life (Columbia-10yrs and Columbia-15yrs) and the IRRs for delivery to DuBois via Micro-Grid at 10 and 15 year project life (DuBois-10yrs and DuBois 15yrs) react to changes in price, assuming a 2.95% decline in production per year. As evidenced
in the Figure 6.1-1, as price increases, the advantage of the DuBois projects over the Columbia projects increase, while the difference between the two project life options for each of the scenarios decreases. From that one might be able to deduce that increasing prices emphasize the advantage of a shorter pipeline or that the higher prices accentuate the implicit extra compression costs. If the latter is true, it could help make a case for natural gas Micro-Grids when prices are high.

Figure 6.1-1: The effect of a varying natural gas price on IRR

In order to assess which costs were affecting the projects the most, the net present value of each cost category was taken and expressed as a percentage of the NPV of all costs. The opportunity cost of one unit of gas used for compression was assumed to be the price of one unit of sale gas. The results of this analysis are displayed in Figure 6.1-1 above. Approximately 90% of the costs associated with these projects are functions of the length of the pipeline. This makes it clear to what degree these projects are affected by the extent and structure of the pipeline system. This issue is addressed further in the Penn State and NCL case, for which more extensive and accurate infrastructure data was available.
Next, the model was applied to the Penn State and NCL Resources case. There were four scenarios in this case: delivering directly to the pipeline, building a Micro-Grid to Penn State, and shortening the Micro-Grid by 12 and 24 miles from the Penn State delivery point. The last two scenarios do not deliver gas to Penn State, but to another customer along the Penn State scenario Micro-Grid within the allotted distance. Below in Tables 6.2-1 and 6.2-2 are the pipeline and compressor costs for each of these scenarios. For the scenario using the pipeline, its capital expenditures are made up completely of the cost of the compressors, as there are no pipelines to be built. The compressor costs for the pipeline scenario is significantly larger than the other three scenarios because more horsepower is needed to meet the compression requirements of the transmission pipeline. According to the cost structure of the model, the pipeline costs of the other scenarios decrease by approximately $10 million for every 12
miles that the Micro-Grid is shortened. The compressor costs are fairly similar for the three Micro-Grid scenarios.

Table 6.2-1: Pipeline Costs (*in $1000s*)

<table>
<thead>
<tr>
<th>Category</th>
<th>Pipeline</th>
<th>PennState</th>
<th>Short ~12 mi</th>
<th>Short ~24 mi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Materials</td>
<td>-</td>
<td>$4,451</td>
<td>$3,054</td>
<td>$1,471</td>
</tr>
<tr>
<td>Labor</td>
<td>-</td>
<td>$18,440</td>
<td>$12,900</td>
<td>$7,209</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>-</td>
<td>$5,531</td>
<td>$3,786</td>
<td>$1,875</td>
</tr>
<tr>
<td>Right of Way</td>
<td>-</td>
<td>$2,043</td>
<td>$1,437</td>
<td>$841</td>
</tr>
<tr>
<td>Total</td>
<td>-</td>
<td>$30,465</td>
<td>$21,177</td>
<td>$11,396</td>
</tr>
</tbody>
</table>

Table 6.2-2: Compressor Costs

<table>
<thead>
<tr>
<th>Compression Costs</th>
<th>Pipeline</th>
<th>PennState</th>
<th>Short ~12 mi</th>
<th>Short ~24mi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost per BHP</td>
<td>$3,000.00</td>
<td>$3,000.00</td>
<td>$3,000.00</td>
<td>$3,000.00</td>
</tr>
<tr>
<td>BHP</td>
<td>1,521</td>
<td>775</td>
<td>767</td>
<td>553</td>
</tr>
<tr>
<td>Cost (<em>in $1000s</em>)</td>
<td>$4,564</td>
<td>$2,325</td>
<td>$2,300</td>
<td>$1,658</td>
</tr>
</tbody>
</table>

The NPVs and the IRRs are displayed in Tables 6.1-3 and 6.1-4. With by far the lowest capital expenditure, the pipeline scenario clearly has the highest IRR. Even in the best case scenario, with the unrealistic assumption of flat production and a 15 year project life, the Penn State scenario is just under the 15% IRR hurdle. Shortening the Micro-Grid, however, brings on tremendous increases in IRR. The worst case scenario of a 10 year project life and a production decline of 2.95% still results in a 17.69% IRR for the Micro-Grid shortened by 12 miles and a whopping 42.28% for the one shortened by 24 miles. Unfortunately these are overshadowed by the 100+% IRRs of the pipeline scenario.

Table 6.1-3: Summary of Net Present Values (*in $1000s*)

<table>
<thead>
<tr>
<th></th>
<th>Pipeline</th>
<th>PennState</th>
<th>Short ~12 mi</th>
<th>Short ~24mi</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 year project life</td>
<td>$45,558</td>
<td>$15,190</td>
<td>$25,346</td>
<td>$35,932</td>
</tr>
<tr>
<td>10 yr with 2.95% decline</td>
<td>$39,871</td>
<td>$9,372</td>
<td>$19,650</td>
<td>$30,304</td>
</tr>
<tr>
<td>15 year project life</td>
<td>$46,011</td>
<td>$14,617</td>
<td>$24,804</td>
<td>$36,034</td>
</tr>
<tr>
<td>15 yr with 2.95% decline</td>
<td>$30,665</td>
<td>$6,618</td>
<td>$17,347</td>
<td>$28,566</td>
</tr>
</tbody>
</table>
Table 6.1-4: Summary of Internal Rate of Returns

<table>
<thead>
<tr>
<th></th>
<th>Pipeline</th>
<th>PennState</th>
<th>Short ~12 mi</th>
<th>Short ~24 mi</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 year project life</td>
<td>124.49%</td>
<td>10.69%</td>
<td>20.36%</td>
<td>42.18%</td>
</tr>
<tr>
<td>10 yr with 2.95% decline</td>
<td>121.73%</td>
<td>7.90%</td>
<td>17.69%</td>
<td>39.54%</td>
</tr>
<tr>
<td>15 year project life</td>
<td>124.53%</td>
<td>14.31%</td>
<td>22.75%</td>
<td>43.27%</td>
</tr>
<tr>
<td>15 yr with 2.95% decline</td>
<td>121.73%</td>
<td>10.82%</td>
<td>19.78%</td>
<td>40.40%</td>
</tr>
</tbody>
</table>

Sensitivity Analysis

Figure 6.2-1: Composition of NPV of Costs

As in the Clearfield Case, the composition of the net present value of the costs was evaluated. The results of the analysis are displayed in Figure 6.2-1. As expected, nearly the entire pipeline scenario is made up of the capital expenditure needed for compressor stations. The remaining portion is the implied compression costs and tariff. The graph indicates that the decrease in distance not only decreases the cost of installing the pipelines, but it also decreases the relative cost compared to the compressors and compression costs (this is too small, however, to observe on graph). Overall, changing the distance does not have that great affect on the composition of the net present value of costs.

The interaction between natural gas prices, distance and IRR is displayed below in Figure 6.2-2. Each line contains a set of price-distance combinations that obtain a constant IRR. Intuitively, the higher
IRRs require higher prices. What is interesting from the graph, however, is that the difference between two isolines increases as distance increases. This means that to jump from a 10% IRR to a 15% IRR requires a greater price increase at 40 miles than at 15 miles.

![Figure 6.2-2: Price vs. Distance – IRR Isolines](image)

![Figure 6.2-3: IRR vs. Distance – Delivery Pressure Isolines](image)

From Figure 6.2-3 it is apparent that the delivery pressure’s effect on IRR is minimal. This effect becomes nearly nonexistent as distance increases. The lines seem to cross at some point between 20
and 25 miles. This seems counterintuitive, but can be explained by the fact that different delivery point pressures may require different diameter pipelines, changing the capital costs and, therefore, the IRR of the Micro-Grid analysis.
7. Conclusions

From the case studies completed, there appear to be scenarios in which the conditions are right to make a natural gas Micro-Grid economically feasible. The capital costs of building the pipelines, and therefore the distance that the pipeline covers has a large effect on this feasibility. Absolute feasibility is important, but when making a business decision, relative feasibility – choosing the most profitable option – is what is important. For this reason, the pipeline access alternatives would play a huge role in the Micro-Grid decision making process. If a group of wells has access and permission to utilize a transmission line and has existing infrastructure to get its gas there, with compression costs being such a low portion of the Micro-Grid projects evaluated, even a doubling of the necessary compression would not make building a Micro-Grid a more economically viable option than paying the cost of higher compression.

If, however, a group of wells is having difficulty securing access to a pipeline or does not have infrastructure in place to reach it already, then a Micro-Grid could be the best choice. Under these circumstances, whether the Micro-Grid would be considered a good investment would depend chiefly on the combination of sale gas, natural gas price, and distance to the end user. Assuming a 10 year project life, a 15% hurdle rate, the annual sale gas amounting to approximately 2500 to 3500 MMscf, and a price of $4 per Mcf, the pipeline project would reach the hurdle with distances of up to approximately 30 miles. Keeping all else constant, the tradeoff between distance and price is 10 to 15 cents per mile, meaning for each additional mile of pipeline, the price of natural gas would need to increase $0.10-$0.15 to meet the IRR hurdle.

Further Analysis

There are some aspects that would prove to be pertinent in the analysis of a Micro-Grid that have not been considered in this investigation. First, both case studies focused on areas that had low
pressure, low volume wells. It could be interesting to consider using a Micro-Grid for high pressure, high volume wells and see if the increase in sale gas outweighs the increase in diameter (and therefore increase in capital costs) necessary for higher volumes of production. Also, no thought was given to what governmental body would regulate a Micro-Grid and what these regulations would require of the operator. Additional taxes or fees introduced by a regulator could impact the economic outcomes. Furthermore, the cost structure for the pipeline came from a regression analysis of industry costs and, therefore, could easily be over or underestimating the costs. This may hold especially true for the right of way costs which can vary greatly depending on the type and number of properties and terrains that the pipeline crosses. Clearly, more research is necessary to come to solid conclusions, but, at this point, a natural gal Micro-Grid seems that it could be a promising solution to a looming problem.
8. Works Cited


EDUCATION

Current Student (estimated graduation: Spring 2012)  Fall ’08-Present
Schreyer Honors College, Pennsylvania State University, University Park, PA
B.S. in Energy Business and Finance (EBF); Economics minor
Exchange Student  Spring 2011
University of Bath, Bath, United Kingdom

EMPLOYMENT HISTORY

Metals and Mining Equity Research Intern  Summer 2011
Rodman & Renshaw, New York, NY
♦ Collaborated with senior analyst to research and write industry and company sell-side reports, focusing on
growth equity shares of copper, gold, uranium, silver, and iron ore exploration & production names
♦ Gained proficiency in using Bloomberg Professional for industry and company research
♦ Responsible for collecting and analyzing industry and economic data (concerning prices, indices, resource
usage and production) and compiling the information into a marketing handout for meetings with clientele

Accounting Intern  Summer 2010, Dec ’10-Jan ’11
John Templeton Foundation, West Conshohocken, PA
♦ Worked with department controller to develop 2011 budget
♦ Collaborated with CFO to draft a Request for Proposal (RFP) for tax and audit services
♦ Operated ERP software daily to post journal entries, manage accounts and perform reconciliations

SKILLS PROFILE

♦ Analytical and problem solving skills  ♦ Proficient in Word, Excel, Bloomberg, and ArcMap
♦ Excels in a team environment  ♦ Learns and adapts quickly

SELECT COURSEWORK

♦ Demand Response and the Smart Grid  ♦ Adv. Financial Modeling (with VBA programming)
♦ Risk Management in Energy Industries  ♦ Global Finance for Earth & Energy Industries
♦ Financial and Managerial Accounting  ♦ Introduction to Electricity Markets

AWARDS AND DISTINCTIONS

♦ Hess Scholarship for EME  Fall ’11-Spring ’12
♦ R. Wayne Atwell Scholarship for Academic Excellence: Three-time recipient  Fall ’09 - Spring ‘12
♦ Charles B. Manula Memorial Scholarship: Two-time recipient  Fall ’09 - Spring ’11
♦ Graduated highest ranked female of the high school class(3rd overall of 650+): June 2008
♦ Marine Corps. Excellence in Academics Award  May 2008
♦ I Dare You Leadership Award  May 2007

ACTIVITIES AND LEADERSHIP

Economics Teaching Assistant  Fall ’10. Fall ’11
EBF Society: General Member  Fall ’08-Present
Penn State IFC/Panhellenic Dance Marathon  Fall ’08-Present
♦ OPPerations committee member: RYB Chair (committee’s liaison to Rules and Regs and Morale)
♦ A-7 THON and DITTO general member
EME Ambassador  2010/2011 Academic Year
♦ Selection based on ability to lead, communicate, be enthusiastic, and work in a team
♦ Work closely with staff to promote the department’s programs to past, current, and future students