REALIGNING INCENTIVES IN PENNSYLVANIAS NATURAL GAS INDUSTRY THROUGH ENVIRONMENTAL BONDING

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SPRING 2013

A thesis
submitted in partial fulfillment
of the requirements
for a baccalaureate degree in
Energy, Business & Finance
with honors in Energy, Business & Finance

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ABSTRACT

Current policy regarding bonding of natural gas wells in Pennsylvania likely leads to socially inefficient outcomes. This is due to the fact that incentives provided to producers may lead them to leave certain costs associated with natural gas production to society. Particularly, bonding requirements may incentivize operators to leave plugging and reclamation costs to society, creating an externality. At the heart of the issue is that current bond amounts do not reflect the expected costs of reclamation and plugging. In short: incentives are misaligned.

This paper will proceed by examining the problem in detail, establishing the importance of addressing the problem, offering possible solutions to the issue of misaligned incentives, and eventually advocating for a policy based on full-cost, site specific bonds.
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ACKNOWLEDGEMENTS

There are a number of people, without whom, this thesis would not be possible. I would first like to extend my gratitude to my readers, Dr. Andrew Kleit and Dr. Anastasia Shcherbakova for their continued support and guidance during the preparation of this thesis.

I would like to thank Dr. Mark Brennan for being a wonderful mentor and providing me with life changing opportunities. I would additionally like to thank Dr. RJ Briggs and Dr. Michael Milligan for their help inside and outside of the classroom over these last four years.

Finally, I would like to extend my thanks and love to my family and friends. To Nicole Holden, for proofreading, support and encouragement. To my brother and sister, James and Rebecca Edwards, for showing me the value of hard work. And finally, to my parents, whose continued encouragement and guidance made this thesis possible, and whose love has never failed me.
Chapter 1

Introduction

Pennsylvania has long played a prominent role in the production of energy in the United States. In 1859, the first oil well in the country was drilled in Titusville, Pennsylvania (PADEP, 2013). By the dawn of the twentieth century, Pennsylvania was the national leader in coal production, and in 1918 produced 277 million short tons of bituminous and anthracite coal (Milici, 2013). A century later, Pennsylvania again finds itself at the vanguard of yet another energy revolution.

Pennsylvania sits atop a massive geologic formation known as the Marcellus Shale. The Marcellus formation stretches from New York to Kentucky, covering a large swath of Pennsylvania. The USGS estimates that the Marcellus formation contains 84 trillion cubic feet of undiscovered and recoverable natural gas and 3.4 billion barrels of natural gas liquids, making it the largest unconventional gas basin the USGS has examined (Schenk, Pierce & Demas, 2012; Pierce, Coleman & Demas, 2011). Researchers estimate that by 2020, Pennsylvania will have brought in over $1.8 billion in local and state tax revenue as a result of natural gas production in the Marcellus Shale (Considine, Watson, Blumsack 2012).

Until recently, the technology to harvest this gas did not exist or was prohibitively expensive. However, recent engineering and technological advances coupled with an increasing demand for natural gas has made the development of the Marcellus economically viable (Alter, Brasier, McLaughlin, Willits & Fern, 2010). Harvesting gas trapped within the Marcellus Shale requires techniques such as hydraulic fracturing and horizontal drilling. These techniques are not
typically employed when drilling for gas in shallower, looser formations (PennFuture, 2013). For this reason, wells drilled into the Marcellus formation are classified as “unconventional wells.”

Since 2005, there have been over 13,000 unconventional gas wells permits issued by the Pennsylvania Department of Environmental Protection (PADEP, 2013). For example, during the week of March 11, 2013 about 100 new permits were issued and 26 new unconventional wells drilled, or “spud.” (PADEP, 2013). In 2010, shale gas accounted for 23 percent of all natural gas production in the United States. By 2035 shale gas is expected to account for about half of all gas production (Davis, 2012). Thus, the number of unconventional gas wells is expected to increase in coming years at rates of more than 1,000 new unconventional spuds a year (Mitchell & Casman, 2011).

While still in the nascent stages of a shale gas boom throughout Appalachia, it is critical to review the current policies governing gas resource development. Reliable empirical data concerning environmental risks from natural gas drilling has not yet become widely available (Davis, 2012). However, current policies have likely led to socially inefficient outcomes. Environmental costs, such as gas wells left unplugged and drilling sites left un-reclaimed, create a burden on taxpayers; not only are taxpayers left to finance cleanup efforts, but un-reclaimed land can lead to lower property values and prevent land from being put to other uses (Mitchell & Casman, 2011). This can be viewed as a result of misaligned incentives within the regulatory framework.

This paper will proceed by first examining the nature of the (dis)incentives within Pennsylvania’s natural gas industry. Next, the paper will establish the importance of realigning incentives through a discussion of possible outcomes of misaligned incentives. Finally, through discussion of different forms of financial assurance, this paper will advocate for a full-cost and site-specific bonding mechanism which will incentivize producers to internalize environmental costs and allocate resources in a more socially efficient manner.
Chapter 2
Misaligned Incentives

The economic benefits of a natural gas well accrue from the market demand for natural gas. The price of natural gas has fallen substantially in recent years, mostly due to oversupply from the increased production of shale gas (Davis, 2012). In the last five years, the spot price for one thousand cubic feet of natural gas has fallen almost 75 percent, from over $13/mcf to $3.42/mcf. Figure 2 displays the decline in wellhead prices between May 2008 and late February 2013.

Figure 2-1: Natural Gas NYMEX Spot Prices (May 2008-Feb. 2013)

Source: BarChart.com

For a number of reasons, the prospects for the utilization of natural gas remain positive. A 2011 MIT study stated that due to its multiple end uses, high availability, low price, and reduced carbon emissions relative to fuel-oil, natural gas could be considered a stepping stone to a less fossil-fuel dependent future (Moniz, Jacoby, Meggs, et al., 2011). Lucas Davis (2009) of UC Berkley wrote that natural gas could be seen as a “blue bridge to a green future.” Finally, the Department of Energy projects that shale gas will make up 49% of natural gas production in the
United States by 2035 (Davis, 2012; EIA, 2012). These advantages do not come without costs, however.

Drilling and operation costs are encountered before and during a well’s economic production phase. These costs are highly dependent upon the full bore length of the well, including vertical and horizontal portions (EQT Production, 2012). Table 2-1 displays a cost matrix assembled by EQT Production which details costs associated with wells of various lengths. According to EQT’s data, the price of drilling and operating an unconventional well ranges from $4.7 million to $7.5 million depending on lateral length of the wellbore. In table 2-1, below, fixed costs represent leasing and operating expenses (LOE) associated with production, in addition to drilling vertical portions of the wellbore, which is about 6,000-7,000 feet in EQT’s region of operation (EQT Production, 2013; Penn State Marcellus Center for Outreach and Research, 2013). Variable drilling costs are those costs associated with the drilling of a well (drilling, casing, cementing, etc.). These costs increase as the well depth increases. The term “depth,” in this paper refers to vertical and horizontal portions unless otherwise specified. Wells drilled into the Marcellus formation typically take advantage of horizontal drilling, which carries a cost premium over vertical drilling of up to 300% per foot (Energy Information Administration, 2013; Middle East Well Evaluation Review, 1995). The fixed costs, representing lease and operating expenses (LOE) are amortized over the life of the well, as they include such costs as “lifting” gas (i.e., getting gas out of the ground), routine maintenance, and labor. In 2011 LOE for EQT were about $0.70 per mcf. These costs are encountered over the life of the well (Dunman, 2012). The variable drilling costs are encountered upfront during the drilling phase. As such these costs represent upfront capital expenditures.
Consider a hypothetical well, EMS-01, which is average in every way. Mitchell and Casman (2011) found that the average depth of unconventional wells in Pennsylvania in 2010 was 10,675 ft, thus this is the total depth of EMS-01. A well of this total depth would have a lateral length of between 4,800 to 5,300 feet. This lateral length puts the total costs of drilling and development for EMS-01 between $5.7 million and $6.1 million.

After and before production has ceased on a well, the site must be reclaimed. Reclamation is the process of returning a drill site to a “near natural” state. Reclamation is a two-stage process. Stage one occurs shortly after production begins, and consists primarily of reducing the size of the concrete well pad and removing equipment necessary for well development. Stage two occurs after drilling operations have ceased and consists of reducing the footprint even further, as well as replanting native vegetation and trees, implementing a long term water management plan, as well as any other activities needed to fulfill the goals of reclamation (Andersen & Coupal, 2009). In Colorado, state law requires that this process is to take no longer than three months on crop land, and no longer than six months on non-crop land (Robinson, 2011). Pennsylvania law requires this process to be completed within one year of permanent well abandonment (Mitchell & Casman, 2011).

Another expected cost associated with the closure of natural gas wells is the cost of plugging the well itself. Plugging a well consists of filling the wellbore with cement and sealing materials, in addition to removing upper portions of the well casing and pump (Iowa Department

### Table 2-1: Costs Associated with Well Drilling and Operation

<table>
<thead>
<tr>
<th>Lateral Length (Ft)</th>
<th>3,600</th>
<th>4,800</th>
<th>5,300</th>
<th>5,700</th>
<th>6,900</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed Costs ($MM)</td>
<td>$1.7</td>
<td>$1.7</td>
<td>$1.7</td>
<td>$1.7</td>
<td>$1.7</td>
</tr>
<tr>
<td>Variable Drilling Costs ($MM)</td>
<td>3.0</td>
<td>4.0</td>
<td>4.4</td>
<td>4.8</td>
<td>5.8</td>
</tr>
<tr>
<td>Total ($MM)</td>
<td>4.7</td>
<td>5.7</td>
<td>6.1</td>
<td>6.5</td>
<td>7.5</td>
</tr>
</tbody>
</table>

*Source: EQT Production*
of Natural Resources, 2013). The costs associated with plugging wells are dependent on their depth (including vertical and horizontal portions); the longer the well, the more expensive it is to plug (Andersen & Coupal, 2009).

Anderson and Coupal (2009) estimated that the costs of reclamation and plugging are $34.45 per meter of well depth. Andersen and Coupal’s methodology to find the cost of well plugging and reclamation can be applied to data from Pennsylvania gas activity. Andersen and Coupal (2009) noted that cost of plugging and reclamation activities are most strongly correlated with total well depth at a site (i.e., the sum of all individual wells at a drilling site). This correlation is noted elsewhere in the literature (Davis, 2012; Mitchell & Casman, 2011; Igarashu, et al., 2010).

I will estimate the per foot costs of plugging and reclamation using three different approaches. The first approach uses data gleaned from the most recent PADEP contract offering for well plugging, and PADEP’s estimated contract value. The second approach applies the average depth of orphaned and abandoned wells to all wells plugged with PADEP funds money between 2008-2009, to arrive at a cost per foot value. Finally, using precise data concerning the cost of plugging 17 wells, the depths of which are known, I will divide the cost by the total well depth to arrive at a cost per foot value.

1. The most recent contract for well plugging services, BOGM 11-8R2, is for the plugging and reclamation services of eight wells of about 3,500 feet each. Thus the total depth is 28,000 feet. The contract was estimated by PADEP to be worth between $100,000 and $500,000. Thus, the per foot cost of reclamation between $3.57 and $17.86, with an average of $10.71.

2. As of February 2011 the Abandoned and Orphan Well database maintained by PADEP had 8,523 entries. Of these the depths were known for 933, or about 11%. The average depth of an abandoned or orphaned well in 2011 was 1,737 feet (Abandoned and Orphaned Wells, 2011). During 2008-2009 PADEP awarded $5.3 million in contracts to plug 435 wells. The total depth plugged (1,737 x 425) was about 738,225 feet. Thus, the cost per foot of plugging comes to $7.18, exclusive of reclamation costs, which typically make up 33% of total plugging and reclamation costs.
3. On contract BOGM 11-5, PADEP solicited bids for a contract for the plugging of 17 wells, the depths of which were known. The total depth of the 17 wells is 34,583 feet. PADEP received two bids on this contract section, $88,315 and $335,546. The average of the bids on the contract was $211,930, and the average per-foot cost of the bids for plugging services was $6.12 (Abstract of Bids on Contract BOGM 11-5, 2012). Again, this represents about two-thirds of the total costs of reclamation and plugging.

The table below provides a summary of the above findings:

<table>
<thead>
<tr>
<th>Data Set</th>
<th>Depth Known?</th>
<th>Total Cost</th>
<th>Total Depth</th>
<th>Per Foot Plugging Cost</th>
<th>Per Foot Plugging and Reclamation Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contract BOGM 11-8R2</td>
<td>Yes</td>
<td>$300M Avg.</td>
<td>28M</td>
<td>$7.14</td>
<td>$10.71</td>
</tr>
<tr>
<td>425 wells plugged 2007-2008</td>
<td>Avg. Depth Used</td>
<td>$5.3MM</td>
<td>738M</td>
<td>$7.18</td>
<td>$10.77</td>
</tr>
<tr>
<td>Contract BOGM 11-5</td>
<td>Yes</td>
<td>$211,930</td>
<td>35M</td>
<td>$6.12</td>
<td>$9.18</td>
</tr>
</tbody>
</table>

*Table 2-2: Per foot costs of plugging and reclamation, calculated by dividing total cost by total well depth, using three different data sets and the methodology of Andersen & Coupal (2009).*

The estimate derived above are of similar magnitude, so I can conclude that typical wells in the Marcellus Shale, such as EMS-01, would have a total plugging and reclamation costs of between $98,000 and $115,000.

Possible costs associated with natural gas production arise when an event occurs which requires additional reclamation or cleanup efforts. For example, in 2010, Cabot Oil and Gas was implicated in the contamination of drinking water for 14 households in Dimock Township, Susquehanna County, Pennsylvania – an allegation that Cabot has denied. In response to these claims, Cabot paid over $8 million for the supply of potable water, well plugging, testing, methane treatment systems, and fees of expert environmental consultants. This sum does not include damage to reputation, which may have made the true cost of the water contamination much more than the $8 million settlement.
In 2012, Cabot Oil & Gas realized operating revenue of over $937 million and gross profits (i.e., revenues less operating costs) of over $855 million, despite an 18% year over year decline in the price of natural gas. The company’s stock (NYSE: COG) was trading at about $65 per share at the start of April, 2013, and reached an all time high of about $69 in March, 2013. (Cabot Oil & Gas, 2013; Google Finance, 2013). It is hard to imagine that firms without the financial resources of Cabot Oil & Gas would be able to bear these financial burdens (Consent Order and Settlement Agreement in the Matter of Cabot Oil & Gas Corporation, Dimock and Springville Townships, 2010).

Natural gas can be a profitable and expensive industry at the same time. Operators are willing to pay high exploration and development costs because they anticipate future benefits accruing. However, the expenses involved with reclamation activities do not carry any future benefits. Reclamation alone offers no return on investment. From the view point of a profit-seeking operator, there is simply no reason to engage in reclamation.

This problem has not gone unnoticed in the halls of the state Capitol. In 1984 the state legislature enacted the 1984 Oil and Gas Act, which mandated that firms post a bond prior to commencing operations in order to ensure proper plugging and reclamation. The idea was that if a firm performed proper reclamation, the bonds would be released back to the operator. If an operator did not perform proper reclamation, the bonded money was to be put to use by the state for reclaiming the drilling site (Mitchell, 2013). Bonds were required in the amount of $2,500 for single wells or $10,000 for all wells operated by a firm within the state. This bond was intended to force firms to internalize the costs of plugging and reclamation.

In 2012, bonding requirements for natural gas wells were updated by the Pennsylvania legislature with the passage of Pennsylvania Act 13. The act lays out a tiered system based on depth and number of wells. Table 2-3 displays the bonding amounts. The legislature decided on a 6,000-foot (1,828m) threshold. This depth effectively separates conventional wells (typically
less than 6,000 ft.) from unconventional wells (typically greater than 6,000 ft.). The bonding schedule uses two fees to determine the total bond amount: a base amount and marginal amount. The base amount is dependent on the number of wells in operation. The marginal bond amount is the amount that is added to the base amount for every well in excess of the lower bound of the base amount.

For wells less than 6,000 feet deep, including horizontal portions, the marginal bond amount is $4,000 per well in addition to a base bond amount dependent on number of wells in operation. For wells of depth greater than 6,000 feet, the per-well bond amount is set at $10,000, in addition to the base bond amount that is dependent on number of wells in operation. Blanket bonds—single bonds which can be used to cover all of an operator’s wells within the state—are also available.

<table>
<thead>
<tr>
<th>Number of Wells</th>
<th>Base Bond Amt.</th>
<th>Marginal Bond Amt.</th>
<th>Blanket Bond Amt.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-50</td>
<td>$0</td>
<td>$4,000</td>
<td>$35,000</td>
</tr>
<tr>
<td>51-150</td>
<td>$35,000</td>
<td>$4,000 per well in excess of 50</td>
<td>$60,000</td>
</tr>
<tr>
<td>151-250</td>
<td>$60,000</td>
<td>$4,000 per well in excess of 150</td>
<td>$100,000</td>
</tr>
<tr>
<td>≥250+</td>
<td>$100,000</td>
<td>$4,000 per well in excess of 250</td>
<td>$250,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Number of Wells</th>
<th>Base Bond Amt.</th>
<th>Marginal Bond Amt.</th>
<th>Blanket Bond Amt.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-25</td>
<td>$0</td>
<td>$10,000</td>
<td>$140,000</td>
</tr>
<tr>
<td>26-50</td>
<td>$140,000</td>
<td>$10,000 per well in excess of 25</td>
<td>$290,000</td>
</tr>
<tr>
<td>51-150</td>
<td>$290,000</td>
<td>$10,000 per well in excess of 150</td>
<td>$430,000</td>
</tr>
<tr>
<td>≥250+</td>
<td>$430,000</td>
<td>$10,000 per well in excess of 250</td>
<td>$600,000</td>
</tr>
</tbody>
</table>

Table 2-3: Pennsylvania Bonding Amounts Under PA Act 13 of 2012. Bond amounts are determined based upon number of wells and whether a well is greater than or less than 6,000 ft.

Profit-seeking producers will select the lowest possible bond amount required by law to avoid tying up assets for extended periods of time. For example, instead of posting $250,000 in
individual bonds, the operator of 25 wells greater than 6,000 ft. will elect to post one $140,000 bond, thereby retaining $110,000 in cash or other assets. With this in mind, Figure 2-2 displays cumulative bonding amounts as a function of number of wells. The bonding schedule under PA Act 13 provides incentives to pool risk through the use of blanket bonds. In fact, it is only advantageous to use per-well bonds when a firm operates less than 15 wells of depth greater than 6,000 ft. The maximum bonding amount for an unlimited number of wells is $600,000. Considering that costs of reclamation and plugging a single well can run into six figures, this amount seems inadequate.

![Min. Cumulative Bonding Amount](image)

*Figure 2-2: Minimum Cumulative Bonding Amounts under PA Act 13. Risk pooling through use of blanket bonds is incentivized.*

Blanket bonds are intended to allow producers to pool their operations under one bond. In addition to cutting down on the paperwork and regulatory filings which would be required in filing individual bonds, blanket bonds allow for more operations to be covered under a single bond, thereby freeing capital for investment in other areas. On the federal level, blanket bonds are available only under certain conditions. These conditions include (1) having “spotless”
history or plugging and reclamation compliance (2) having at least one lease with an expected remaining economic life of at least five years (3) having been in operation for at least five years (4) having been producing on more than one lease (5) operates more than ten wells (6) can pass a financial ratio test (ratio test requirements available in Appendix B) (EPA, 1985).

On a per well basis, the misalignment of incentives becomes even more apparent. Because each well needs to be plugged and reclaimed, each well will need its own funds. Under PA Act 13, a single blanket bond could serve anywhere from two to upwards of 250 natural gas wells. Figure 2-3 displays the average amount of bonded money allocated to each well as a function of number of wells. This is not to say that each well will be left un-reclaimed, rather that each well will need to be reclaimed at some point, and thus should have funds dedicated for this purpose. This data was found using the above minimum cumulative bonding amounts, divided by number of wells. This figure reveals that the maximum amount of bonded monies per well is just $10,000. As the number of wells increases beyond the scope of Figure 4, the amount of bonded monies per well approaches zero. These amounts are simply too low to serve their intended purpose of forcing firms to internalize the costs of plugging wells and reclaiming sites.
Figure 2-3: Bonded Monies per Well displayed as a function of number of wells. Maximum bonded amount is $10,000 which occurs at n = 1-25

The operator of EMS-01, EMS Exploration and Production, is an average operator, in that it operates the average number of wells operated by a firm engaged in unconventional drilling in Pennsylvania. In 2012, the average number of productive unconventional wells operated by firms engaged in unconventional drilling was 2.6 (SmithBits, 2013). Thus, the bond amount required by EMS Exploration and Production is either $10,000 per well on 2.6 (rounded to 3) for a total of $30,000 or a blanket bond of $140,000. Because EMS Exploration and Production is a profit maximizing firm, it will opt for three individual bonds.

In some cases, Pennsylvania does not require operators to post bonds in the traditional sense. In Pennsylvania and other states, a “demonstration of assets,” is often used in place of a bond (Mitchell & Casman, 2011). Under this system, a firm simply has to show that they possess assets valued at or above the requisite bonding amount. This is problematic because the process of seizing assets and liquidating them, not to mention the legal process involved, can cost valuable time and even more tax payer money. Timely response to an abandoned well or accident time is paramount to the goal of minimizing damage to an ecosystem (Boyd, 2001).
The problem is identified: In Pennsylvania’s natural gas industry, incentives offered by current regulation likely lead to inefficient outcomes. At EMS-01, the costs of reclamation range from about $98,000 to $117,000, yet the amount of bonded monies is as little as $10,000. This discrepancy can be explained, I believe, through a brief discussion on the economics of public choice.

Pennsylvania’s natural gas industry is composed primarily of small operators operating on only a few permits each. In the last quarter of 2012, the median number of productive drilling operations operated by a natural gas producer in Pennsylvania was one, while the average was 2.6 (SmithBits, 2013). The maximum number of productive drilling operations by a single operator was ten, operated by Range Resources. Imposing regulation on small business is typically politically unpopular (Boyd, 2001). Requiring full cost bonds could alienate hundreds of operators and thousands of employees, some of whom contribute to political campaigns.

Natural gas companies have spent over $23 million on lobbying and campaign contributions in Pennsylvania since 2000. $6.8 million of this spending occurred between 2011-2012 on lobbying efforts, a period which coincides with the debate and passage of PA Act 13 (Marcellus Money, 2012). This data was aggregated from the mandatory filings of campaign contributions and lobbying expenditures in excess of $100 with the Pennsylvania Department of State (Marcellus Money, 2013).

Mitchell (2013) stated in an interview that provisions of PA Act 13 were often built into the bill at the behest of special interest groups or specific legislators, and that no individual or group championed the cause of increasing bonding amounts during the Act 13 debates. Further, Mitchell (2013) and Garber (2013) argue that the issue of bonding may have been obscured by elements of the bill which were deemed more important, such as local zoning control, impact fees, and uniformity across counties.
The literature on the economics of public choice tells us that politicians will favor policies which have short term, identifiable effects, even if the policies lead to inefficient outcomes or the costs of these policies are greater than the benefits (Gwartney, 2009). This is called the Shortsightedness Effect. The time horizon of politicians is only as far as the next election, and politicians seek to maximize their payoffs (i.e., votes) only up to that point. The effects of un-reclaimed natural gas wells may not become apparent for decades, well beyond the time horizon of most politicians. By the time the costs to reclaim these sites are confronted, the politicians who declined to force industry to fund these costs upfront will likely be long gone (Gwartney, 2009).

This implies that one reason why bonding amounts are systematically too low may be that the politicians who craft bonding policy are seeking to maintain or increase the investment from energy firms, which has immediate and identifiable results, while simultaneously ignoring the costs which are likely to arise after their terms have expired.

In discussing bonding requirements with state law makers, Mitchell (2011) cited the low bonding requirements of adjacent Marcellus states as a reason why policy makers favored discounted bonds as opposed to full cost bonds (Shale Gas Well Reclamation Raises Questions, 2011). Ohio, in particular, was cited as a state with low bonding requirements which could divert investment away from Pennsylvania if it were to increase bonding requirements.

A desire to remain competitive relative to other states may be the result of shortsightedness. From the perspective of the Commonwealth, the desirability of being competitive is unclear. On the one hand, increased investment from energy companies may lead to an increased tax base (Considine, Watson & Blumsack, 2010). On the other hand, the monetary costs to society of un-reclaimed sites are hard to predict and may outweigh the benefits. The costs include reclamation itself, as well as any healthcare costs, loss in land use value, loss of
intrinsic and bequest value due to the adverse effects of well sites left un-reclaimed (Mitchell & Casman, 2011).

The result of the misalignment of incentives is that many natural gas wells are abandoned without proper plugging or environmental reclamation (Oil and Gas Accountability Project, 2005). This condition can have numerous adverse effects on the environment and population—locally as well as across a wider geographic region. Mitchell and Casman (2011) note that well sites left un-reclaimed can result in permanent changes to the environment. For example, failure to plug and reclaim well sites after operation can lead to increased siltation and sedimentation, forest fragmentation, higher mortality rate of native plants and animals, decreased biodiversity, and introduction of invasive species of plants (Mitchell & Casman, 2011).

Un-reclaimed natural gas sites present a threat to local waterways and watersheds as well. Millions of gallons of spent hydraulic fracturing fluid containing heavy metals and other chemicals are often stored on sight in large earthen impoundments or transportable containers (Andersen & Coupal, 2009). Ensuring that waste water is disposed properly is essential to the protection of local waterways and environment (Davis, 2012). Further, it is essential to the long term health and viability of the eco-system that these steps are carried out in a timely and effective manner (Mitchell & Casman, 2011). A well left unplugged can allow gas, oil, and fracking fluid to migrate between geologic layers and potentially contaminate groundwater and/or surface water. The literature suggests that sites should be fully reclaimed within three to six months after production has ceased (Robinson, 2010). The contamination of a major body of water, such as the Delaware River, could impact millions of households (Davis, 2012).

For example, a natural gas well operated by Chesapeake Energy Corporation in Bradford County, Pennsylvania experienced a blowout in April 2011. For 12 hours contaminated water flowed from the well, and eventually into the Susquehanna River (Associated Press, 2011). The Susquehanna River flows into the Chesapeake Bay, which has been the focus of environmental
preservation efforts since at least 1988 (Fairfax County Department of Public Works and Environmental Services, 2003). As a result of the blowout and uncontrolled flow of contaminated water, seven families were evacuated from their homes (Associated Press, 2011).

Bonds are not only used to help finance the cleanup efforts of unforeseen events such as those mentioned above, but to finance the routine plugging and reclamation efforts in the event that they need to be carried out by the state. Indeed, this is the function of bonds as expressed in the language of the 1984 Oil and Gas Act (Mitchell, 2013). An operator which goes out of business, or otherwise cannot finance reclamation efforts forfeits its bond to the state. An example of this type is the Emerald Restoration and Production Company (ERPC). In 2001, ERPC filed for bankruptcy, and in doing so forfeited its $125,000 blanket bond to the state of Wyoming. ERPC also left Wyoming with 120 wells in need of plugging and reclamation. The $125,000 bond was woefully inadequate to meet the liabilities of ERPC. As of 2012, more than $2 million in taxpayer money had gone to plugging the wells (Oil and Gas Accountability Project, 2012).

Davis (2012) and Mitchell and Casman (2011) point out that the full effects of the existing misaligned incentives may not be realized for decades or more due to the long production life of natural gas wells and the expected increase in drilling operations in the state. Therefore, it is crucial to examine the existing policies and their effects, as well as ways to mitigate the misalignment of incentives, before taxpayers bear significant financial burdens.
Chapter 3
“The Saudi Arabia of Appalachia”

The gas which is brought to the surface by wells like EMS-01 was formed almost 380 million years ago (Pennsylvania Independent Oil & Gas Association, 2013). Around this time, plants and other carbon-based organisms died and became part of the soil, wetland, etc. With time and pressure, these carbon-based life forms became oil and natural gas—so called fossil fuels (Pisupati, 2008).

Almost 400 million years later, Engelder (2008) announced that a stratum of rock about a mile beneath earth’s surface likely contained enough natural gas to fundamentally alter US energy markets (Silver, 2011). The initial press release, based on Engelder’s calculations stated, “The value of this science could increment the net worth of U.S. energy resources by a trillion dollars, plus or minus billions” (United Press International, 2008). That was all the encouragement industry needed. Between 2008-2009, permits issued by PADEP for Marcellus wells increased 300% (Turner, 2009). Figure 3-1, below, displays the production of natural gas in Pennsylvania over the period 1967-2011. The near-vertical slope of production in the late 2000s is prominent, and due to the development of the Marcellus play.
In 2011, the USGS released a report stating that the Marcellus Shale contained about 84 trillion cubic feet of undiscovered, technically recoverable natural gas. This amount of gas makes the Marcellus Shale the largest shale gas deposit the USGS has analyzed and the second largest natural gas field in the world (Pierce, Coleman & Demas, 2011; Silver, 2011). This gas does not come out of the ground freely however, and as a result highly technical wells must be drilled in order to harvest the gas.

It is often the case that wells are permitted in state forests or other relatively inaccessible locations. Assume our hypothetical well, EMS-01, was permitted in such an area. In order to transport rigs, fluids, and equipment in as well as gas out, it becomes necessary to clear land and construct access roads. Once the site of EMS-01 becomes accessible to equipment and personnel, construction on the EMS-01’s concrete well pad begins. During the drilling and development phases, the well pad will typically be between 4 and 5 acres. After production begins on EMS-
01, the size of the well pad will be reduced to 1 to 3 acres as part of a process known as intermediate reclamation (New York State Department of Environmental Conservation, 2009).

The drilling of EMS-01 is carried out in several stages, each consisting of three steps: drilling, casing and cementing, in that order (Davis, 2012). First, a section of wellbore is drilled. The operator of EMS-01 then place a steel pipe into the bore to reinforce the sides of the well. Cement is then pumped in between the steel casing and the sides of the wellbore, the so-called annular space. This not only further strengthens the well walls, but binds the steel casing to the well bore. This process is carried at progressively deeper depths until the well has reached its target depth.

It is imperative that the operator perform these steps without error in the earliest stages of well construction, because ground water is found at depths of less than 1,000 feet (Davis, 2012). Davis (2012) posits that reported cases of groundwater contamination may, in part, be the result of a failure of the wellbore casing at shallower depths. In Pennsylvania, aquifers are found at depths of no greater than 250 feet (Swistock, 2007). At these depths, impermeable geologic layers known as aquitards restrict, or retard, the flow of water downward (Simpson, 2006).

The shale gas which EMS Exploration and Production are seeking to harvest is located in deep, thin, and dense geologic formations. For this reason, specialized techniques have been developed in order to harvest gas from these formations (Helms, 2008 & Donovan, 2012). Two methods in particular characterize what are known as unconventional gas wells: horizontal drilling and hydraulic fracturing. Horizontal drilling takes place after a target depth has been reached via vertical drilling, and the well bore is turned to drill on a horizontal plane. Horizontal drilling is used to expose more of the wellbore to the gas-bearing rock, which is too thin for conventional vertical wells to produce gas in economically viable quantities (Helms, 2008). Hydraulic fracturing, or “fracking,” is the process of injecting water, sand, and chemicals into the well in order to fracture the dense rock formations, creating fissures that allow gas to migrate to
the wellbore and eventually, to the surface. (Donovan, 2012). This process is repeated until the well cannot produce gas at an economically feasible rate, the so-called economic limit (Hyne, 2001).

Natural gas wells are characterized by steep declines in their production curves over time (EQT Production, 2011). That is, a well will produce a lot of gas in its earliest stages, but that amount will quickly decline as the well ages. Figure 3-3 displays a typical decline curve of a well in the Marcellus Shale. The data come from EQT Production, one of the larger operators in the Marcellus play (Pennsylvania Independent Oil & Gas Association Active Operators, 2013; PADEP Permitted Well Inventory, 2013).

![Marcellus Production Decline Curve](image)

*Figure 3-2: Marcellus Production Decline Curve*

It is especially important to note three characteristics about the decline curve. First: the high initial recovery rate; Second: the steep decline in recovery in a short time; Third: the long lifespan of the well at low recovery rates. These characteristics create a condition in which large exploration and drilling firms can recover their capital expenditures and take profits early in the life of a well due to its high production rate, then divest themselves of the well when its
production asymptotes (Mitchell & Casman, 2011). Often the wells are bought up by smaller firms who lack the capitalization to explore and begin production (Hager & Shaw, 1999). These firms are sometimes referred to as “fly by night” firms. This condition can be observed throughout the nation (Davis, 2012). In part because of this, the industry is predominantly composed of a large number of small firms operating relatively few older—and thus marginally producing—wells purchased from one of the handful of larger exploration and development firms.

Once a well is finished producing, or no longer produces at an economically viable rate, it must be shut down and its site reclaimed. The process of reclaiming a drilling site is highly involved.

Figure 3-3, below displays a graphic depiction of well development.

![Figure 3-3: A graphic depiction of the well development phase. Note two characteristics of unconventional drilling: a horizontal well bore and hydraulic fracturing](source: Al Granberg/ProPublica)
The Marcellus Shale play is an exciting and promising resource with far reaching implications in energy, politics, environmentalism, finance, and a host of other areas. The continued development of the resource, under current regulations, will likely lead to society bearing the cost of the actions of private actors, however. If this is to be avoided, incentives need to be realigned such that operators internalize the costs of reclamation, thereby allocating resources in a more socially efficient manner. The question remains: how?
Chapter 4

Meeting Future Liabilities

Economic theory states that costs should be internalized by those who produce them in order to achieve a more socially efficient outcome. Internalizing costs leads to more efficient allocations of resources (Boyd, 2001). What is problematic about the development of natural gas resources is that the costs associated with plugging and reclamation are not incurred until after a well has ceased production. In the absence of any regulatory framework, why would a profit seeking firm spend money on something which offers no return on investment? They would not—there is no incentive to do so.

Currently, there exist different regulatory frameworks with which states and other regulatory agencies induce cost internalization. This section will provide a comparative analysis of the two primary ways in which regulators approach this issue: bonds and trust funds.

As I discussed in Chapter 2, Pennsylvania currently employs a bonding approach to address the issue of reclamation—though the amounts leave something to be desired. Bonding is a simple, yet remarkably effective tool for inducing cost internalization. Through full cost bonds, the state would compel operators to bear the cost of reclamation, a cost which is operator-created. This provides the operator with a two-fold incentive. First, operators are prone to choose less environmentally-risky operations lest they lose their bond. In addition, firms are incentivized to develop more cost effective reclamation techniques so as to actually net money from the release of a bond (Boyd, 2001). This is the ideal case.

Consider the following simplified model offered by Sult (2004). Prior to operations a firm posts a bond of value $B$. During operations, the firm seeks to minimize the cost of compliance according to:

$$\min C = I(e) + R(e) + F(e)$$
Where:

\[ C = \text{cost of compliance} \]
\[ I = \text{cost of intermediate reclamation} \]
\[ R = \text{cost of final reclamation} \]
\[ F = \text{fines} \]
\[ e = \text{effort to comply} \]

As effort, \( e \), increases, the \( C, I, R, \) and \( F \) take on the following shapes:

At time \( t=T \), the well is ready for final reclamation. The decision to reclaim is a function of the cost of final reclamation, \( R(e) \), relative to the amount of bonded monies, \( B \), as well as costs associated with damage to reputation, \( D \). The operator seeks to minimize the total cost, \( C \), at time \( t=T \) such that:

\[ C|_{t=T} = \min(R(e), B + D) \]

Thus,

\[ R(e) > B + D \Rightarrow \text{Do not Reclaim} \]
\[ R(e) < B + D \Rightarrow \text{Reclaim} \]
At the heart of the choice of whether or not to reclaim is the fact that proper reclamation results in the bond being given back to the operator. Thus, if the cost of reclamation is more than the bond amount plus reputation effects, do not reclaim. If the sum of bond amount and reputation effects is greater than the cost of reclamation, reclaim.

In the case of the decision to reclaim EMS-01, it is clear that the profit-seeking firm would choose not to reclaim because the costs of reclamation far exceed the amount of the bond. From this simplified model it is apparent that increasing the bond amount, $B$, increases the incentives to reclaim sites. If there were no bonding requirements (i.e., $B = 0$), there is no incentive to reclaim and all sites are left un-reclaimed.

There are three main criticisms of a bonding approach to addressing the problem of misaligned incentives. The first is that necessitating liquid bonding instruments invites fraud and abuse by regulators. The second is that full-cost bonding creates a barrier to entry into the market for producers. Third, that full-cost bonding would make Pennsylvania uncompetitive relative to other states such as Ohio (Mitchell & Casman, 2011; Gerard, 2000, Mitchell, 2013; Davis, 2012, Boyd, 2001).

A significant increase in mandatory bond amounts would necessitate strict accounting and payment of interest to hundreds of companies on a regular schedule, not to mention the maintenance of sizeable bond fund. Such a large pool of bonds will generate substantial interest to be paid out to individual operators. Last year Pennsylvania issued 1,484 unconventional well permits (PADEP, 2013). If bond amounts were raised to $100,000, this would generate about $148,400,000 in bonded monies per year if 2012 rates persist, which some observers believe they will (Mitchell & Casman, 2011). At 3% interest that would generate $4,452,000 in interest revenue per year, not an insignificant amount of money to be placed in the care of individuals. In the case of fraud being perpetrated, it would not be the first time public monies were mismanaged in Pennsylvania.
In 2009, former State Senator from Philadelphia, Vincent Fumo was convicted of 137 federal corruption charges ranging from mail fraud to conspiracy. Fumo was accused of, among other things, selling his support for utility deregulation to Exelon Corporation for a $17 million donation to Fumo’s charity, as well as using up to $1 million in state funds for personal expenses (Associated Press, 2007).

More recently, in January, 2013, the State Auditor General found that Millersville University of Pennsylvania deliberately capped contracts at the “no-bid” threshold in order to avoid having to seek competitive bids, as well as awarded exorbitant salary increases to its administrators and employees (DePasquale, 2013).

This criticism is well taken. However, a 2009 audit of the Pennsylvania Hazardous Sites Clean up Fund by state Auditor General Jack Wagner found no malfeasance concerning allocation of fund money (Wagner, 2009). However, the audit did find that the administration of the fund was lacking, citing instances of allocated funds not being spent, poor reporting, and poor oversight (Wagner, 2009). Perhaps a better criticism of the proposal might be that accounting and financial reporting are not typical strengths of regulators (Boyd, 2001). If the proposed plan is to be effective at meeting current and future liabilities, the quality of accounting, reporting and oversight must be increased by the PADEP.

Eugene DePasquale, current Auditor General of Pennsylvania, notified PADEP on January 13, 2013, his first day in office, that he would undertake an audit of PADEP’s efforts at ensuring safe drinking water in light of the shale gas boom in the state (Auditor General DePasquale Initiates Audit to Ensure Safe Drinking Water, 2013). While this audit is not focused on reclamation and bonding specifically, these topics will no doubt be discussed in the audit. Mr. DePasquale’s final report is forthcoming. No date of expected release has been announced (Ciccocioppo, 2013).
To address the concern of possible malfeasance, I would propose that the statewide remediation fund undergo outside independent audits on a regular basis. Currently, the state Office of the Budget Comptroller Operations audits PADEP (as well as other major state agencies) quarterly (Comptroller Operations Single Audit Report, 2013). Enlisting an outside agency to conduct a similar audit on a quarterly basis may be cost prohibitive, but I believe an audit every two years would be appropriate. This interval could be aligned with the end of Secretary of PADEP’s first and third year in office. Audits aligned in this manner reduce the amount of time in which fraud may be perpetrated by an administration or bureaucrat taking advantage of lax administration oversight.

A similar argument is that by requiring easily attachable and liquefiable assets, the policy invites overzealous regulators to abuse their authority by wantonly and inappropriately declaring that sites have not met statutory standards, thereby causing the forfeiture of bonds which should not be forfeited. This is not as much of a concern under the current system because many firms can simply post their assets as collateral (Mitchell & Casman, 2011). The state would have to engage in legal action proving operator liability in order to take control of these assets. For example, in 1998 Allegro Oil and Gas twice appealed the forfeiture of its bonds covering its gas wells. The Pennsylvania Environmental Hearing Board twice issued summary judgments against Allegro Oil and Gas, but the process took almost an entire year (PAEHB, 2013). Under the proposed policy, the state has primacy and it is up to the operator to prove that they are not liable. This is due to the fact that liquid assets such as cash or surety bonds in care of the State Treasurer are easily attachable. This is a subtle but important difference. In addition, I would argue that full cost bonding would in fact incentivize operators to develop new, more effective and vigilant reclamation methods so as to ensure their assets are not seized.

Perhaps the most damaging criticism of the proposed policy is that it creates a situation in which small firms either cannot compete or must receive third party backing in order to do so. In
short, that the proposed policy creates barriers to entry for small firms. However, the data do not support this claim, as a brief discussion of the Penn Virginia Corporation will show. Further, that third party financing is taken for granted as a negative overlooks the nature of underwriting relationships, which instill another level of oversight by the underwriter. Firms deemed to engage in risky or substandard practices will be subject to higher premiums, while firms engaged in best practices will face lower premiums. This further incentivizes producers to operate in a responsible manner (Boyd, 2001). Additionally, some consolidation of the natural gas industry is actually to be desired according to Davis (2012). This is because it may not be desirable to have small, judgment proof, firms engaged in high risk drilling activities.

One example which seems to contradict the idea that higher bond amounts create barriers to entry to small firms is the most recent gas lease auction for Pennsylvania State forest land. To this point, all discussion of bond amounts have focused on bonds for drilling on privately owned land. Interestingly, bond amounts for drilling on state-owned land range from $35,000-$125,000, depending on depth of the well. Additionally, this amount can be adjusted for inflation every five years (PA DCNR, 2013).

These relatively high bond amounts do not preclude successful lease auctions. During the most recent lease auction, the state expected to bring in about $60 million—the actual proceeds were in excess of $128 million (Hurdle, 2010). Penn Virginia Corporation was one of five successful bidders for gas leases in state forests. Penn Virginia Corp. was able to secure 3,698 acres for $13.9 million (Hurdle, 2010). Penn Virginia Corporation is one of the smaller firms in the Pennsylvania Marcellus play, and is currently operating on just 14 permits out of 9,965 active permits, or about one-tenth of one percent of all permits (Pennsylvania Independent Oil & Gas Association Active Operators, 2013). Thus, it is indeed possible for small firms to bid successfully in spite of higher bond requirements.
In all, the two primary criticisms of bonding—that it invites fraud and abuse, and that it creates barriers to entry—are dubious at best and inaccurate at worst. However bonding is not the only approach to meeting future liabilities.

Another way in which future obligations might be met is through funding from trust funds. The idea of a trust fund is that an initial deposit is placed in care of a third party, or trustee, who administers the account for the benefit of another. This differs from the system currently in place in that trust funds require that the initial deposit be only a fraction of the expected liability. In the years between the initial deposit and maturity, the money is invested and (hopefully) grows. In the case of natural gas well reclamation, the trustee might be PADEP or the state treasurer’s office.

In fact, trust funds are already administered by PADEP in order to meet obligations of the energy sector in Pennsylvania—not in the natural gas industry, but the coal industry. (Pennsylvania’s Regulatory Program Amendment Regarding Pennsylvania’s Defunct Alternative Bonding System as Required by 30 C.F.R § 938.16(h) and the Part 732 Notices). One example is the Al Hamilton Trust, which was intended to meet the liabilities associated with post-mining discharge at 14 sites operated by the Al Hamilton Contracting Company. The Al Hamilton Trust is currently experiencing “severe financial stress,” primarily because the value of unsold coal reserves was counted in the initial value of the assets in the trust, similar to a demonstration of assets approach (Al Hamilton Trust Report, 2012). However, even if all of the assets placed in the trust were in the form of cash, it is likely that the trust—and others like it—still would have had issues meeting its obligations in perpetuity, as they were intended to do (Small, 2009).

The advantage of a trust system is that an operator need not place assets valued at the full expected cost of reclamation into the trust at the start of operations. Instead, an operator places an initial amount of money in the trust which is invested such that the trust is fully funded one year after operations have ceased (Small, 2009). This is advantageous because it allows the
operator to maintain capital which can be invested in other areas. The amount placed into the trust at the start of operations is dependent on the expected length of operations at the site, the expected reclamation costs, and the investment market conditions which are anticipated for the life of the trust (Pennsylvania’s Regulatory Program Amendment Regarding Pennsylvania’s Defunct Alternative Bonding System as Required by 30 C.F.R § 938.16(h) and the Part 732 Notices).

For example, if an operator expects that it will cost $200,000 to fully reclaim a drilling site with a life of 20 years, and the state believes its trustees can earn an 8% real return on investment annually, then the present value of the trust in year zero (i.e., the initial deposit) is under $43,000. This sounds like a good plan in theory, but in practice it is not so simple.

The state’s trust fund approach to funding treatment at coal mines and coal refuse sites across the state is currently under legal challenge from groups which consider the program to be fundamentally flawed (Weist, 2013). The main criticism of the trust fund system is that it makes assumptions about the investment markets which are “excessively optimistic” (Small, 2009). The program, as laid out by PADEP, allows for up to 80% of the trust to be invested in US equities and 20% to be invested in bonds (Pennsylvania’s Regulatory Program Amendment Regarding Pennsylvania’s Defunct Alternative Bonding System as Required by 30 C.F.R § 938.16(h) and the Part 732 Notices). In addition, the system assumes an average long-term return of 11.1% on equities (volatility 20%) and 5.25% on bonds (volatility 0%) (Small, 2009). Thus the long-term weighted average return is estimated to be:

\[(0.8 \times 0.111) + (0.2 \times 0.0525) = 0.0993\]

Volatility is similarly calculated via the weighted average of individual volatilities:

\[(0.8 \times 0.2) + (0.2 \times 0.0) = 0.16\]

The figures for expected return and for volatility are not correlated, as laid out in the Commonwealth’s plan; rather they are simple assumptions of the future long term behavior of the
financial markets based on the weighted averages of returns and volatility on equities and debt instruments (Small, 2009).

The problem with this approach is that it is very difficult to predict future returns accurately. The uncertainty inherent in capital markets makes the trust fund approach too risky. In 2002, the S&P 500 index lost 22% of its value; in 2008, 37%. The goal of a trust is to fund liabilities with certainty at a given point in future. Losing even just 10% of the trust’s value the year before expected maturity could be devastating to the reclamation efforts. Thus, reclamation is a low risk tolerance activity for which trust funds offer too much risk (Small, 2009).

Small (2009) conducted a review of PADEP’s proposed trust fund approach and pointed out several additional deficiencies in the program. In particular, the state seems to ignore the basic fact of financial economics that risky assets involve risk (Small, 2009). A touchstone of financial economics is that in order to receive higher returns, one must be willing to accept higher risk. The State’s plan seems to assume that high rates of return are available without the associated risk (Small, 2009). To compound this risk, the state advocates an especially aggressive investment mix of 80% equities. This is simply too much risk for the low-risk-tolerance trust funds (Small, 2009).

In order to contextualize risk tolerance, it is common to use illustrative examples of investors at different stages in life. Malkiel (2011) and Small (2009) both invoke examples of a young professional and an elderly relative in need of long term critical health care. The young professional can afford to have significant risk in her or his portfolio because he/she has a long working life ahead of him/her to make up for any significant drawdowns, as well as the ability to curtail discretionary spending. On the other hand, those in need of critical care in the near future cannot afford to have much risk in their portfolio, because a drawdown of any amount could mean that they cannot afford crucial services. Additionally, those in present need of critical care are often unable to supplement their income or make spending cuts. I would argue, as would
Small (2009), that reclamation activities are much more similar to the risk-averse elderly relative than the up and coming professional.

Another, more puzzling, question concerning PADEP’s trust funds is something referred to as the volatility multiplier. In order to compensate for the volatility in investment markets, the state advocates for the initial investment amount to be multiplied by one plus the weighted average of the volatilities of debt and equity instruments. “This *ad hoc* procedure has no basis in financial theory. It is an improper way to evaluate and manage the risks associates with volatility in returns” (Small, 2009). In effect, the volatility multiplier is assumed to convert a risky portfolio with an annual return of 9.93% to a *riskless* portfolio with an annual return of 9.16% through increased initial capitalization. If it sounds confusing, that is because it is—this method of accounting for volatility has no basis in financial economics (Small, 2009). A description of the mathematics behind the volatility multiplier is available in Appendix C. Riskless assets available in financial markets simply do not offer that level of return (Small, 2009). Small (2009) pointed out that the real rate of return on riskless assets in 2009 was just 1%.

Finally, upon a review of the actual investments of a number of these trusts, it was determined that the assets were invested in a much more conservative fashion, with less than 50% in domestic equities. While this more circumspect approach will preserve the capital of the trust, shielding it from the level of volatility which would have been seen with an 80/20 mix, this more conservative approach means that the expected amount which will be in the trust at the time of its supposed maturity will be much less than the amount needed to fund full reclamation efforts (Small, 2009).

Small (2009) stresses in his review of PADEP’s trust fund approach that the eventual collapse of the trust fund system is “all but certain.” Small (2009) offers four reasons for this conclusion: (1) that the state makes unrealistic assumptions about the future behavior of financial markets, (2) the state makes problematic assumptions about the investment style which will
actually be practiced, (3) the state relies on operators to make up shortfalls in the trusts, and (4) the trusts are incapable of meeting unexpected liabilities.

Pennsylvania is not the only state which has faced the question of financial assurance. Indeed, it is one of the newer members of the club in terms of financial assurance for shale gas development. Shale plays in Texas and Oklahoma have existed since the 1990s. An examination of financial assurance measures in other states will inform our decisions about how to realign incentives in Pennsylvania. Additionally, financial assurance measures from Pennsylvania’s coal industry will provide lessons from which to draw insight when crafting financial assurance recommendations.
The issue of environmental reclamation is not new, nor is it confined to Pennsylvania or the natural gas industry. Reclamation has been a topic of legislation in the coal industry for at least three decades and shale plays other than the Marcellus exist throughout the nation. This section will examine the approaches to bonding taken by other shale states in order to inform our discussion on Pennsylvania’s bonding policy. The states examined are Ohio, West Virginia, New York, Texas, Montana, Wyoming, Oklahoma, and Alaska. Figure 5-1 displays various shale plays throughout the contiguous lower 48 states. In addition to examining the approaches of other states toward bonding, I will examine the Pennsylvania coal industry and the ways in which it dealt—and is dealing—with the related issues of bonding and land reclamation.

Figure 5-1: Shale Plays in lower 48. Source: Energy Information Administration
Ohio

As of 2011, Ohio ranked twentieth in marketed production of natural gas (EIA, 2011). The reason Ohio lagged behind other states is because the main shale formation in Ohio, the Utica Shale, was considered impermeable and uneconomical until about 2011 (Goodman, 2013). Figure 5-2 displays the increase in permits for the Utica Shale. The figure for 2013 was calculated by assuming the rate of permitting observed throughout March 23, 2013 would remain constant through 2013.

![Ohio Utica Shale Permits Issued](image)

*Figure 5-2: Permits issued by Ohio Department of Natural Resources since 2010. 2013 figure was found using rate observed through March 23, 2013.*

For comparison, during the period of 2009-2012, Pennsylvania issued over 16,000 permits (PADEP Permits Issued Report, 2013).

In order to offset the cost of natural gas development in the state, Ohio requires a permit fee, the amount of which is depended on the population of the township in which the well will be drilled (Ohio Revised Code §1509.06(G), 2012). The permit fees associated with different populations is shown below in table 5-1. One reason Ohio might have chosen to take an approach
to permit fees based on population is that drilling activities will affect more people in more populated areas, and thus, more funds will be needed to offset the associated social costs.

<table>
<thead>
<tr>
<th>Population</th>
<th>Permit Fee ($/well)</th>
</tr>
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<tbody>
<tr>
<td>&gt;5,000</td>
<td>250</td>
</tr>
<tr>
<td>5,000-9,999</td>
<td>500</td>
</tr>
<tr>
<td>10,000-14,999</td>
<td>750</td>
</tr>
<tr>
<td>15,000+</td>
<td>1,000</td>
</tr>
</tbody>
</table>

*Table 5-1: Permit fees as outlined in Ohio Revised Code §1509.06(G) are depended on the population of the municipality in which the well will be drilled.*

*Source: Ohio Revised Code*

Ohio law requires a bond for reclamation in the amount of $5,000 for single wells and $15,000 blanket bonds for all wells within the state (Ohio Revised Code § 1501:9-1-03, 2009).

**West Virginia**

In 2011, West Virginia ranked tenth in natural gas marketed production (EIA, 2011).

West Virginia has long been a central player in the production of natural gas and has until recently produced more gas than Pennsylvania (Natural Gas Gross Withdrawals and Production, 2013). Figure 5-3 displays Pennsylvania’s and West Virginia’s marketed production of natural gas from 1967 to 2011. The rate of production of natural gas from West Virginia is expected to increase, since the number of permits issued by the state has increased each year, with the permit issuance for 2013 on pace to beat the total issued in 2012 (Monthly and Year-to-Date Permit Issuance Averages WVDEP Office of Oil & Gas, 2013)
Operators in West Virginia must submit an initial $10,000 permit fee for the first well in the state, and $5,000 for each additional well (Associated Press, 2011). In addition, individual bonds in the amount of $5,000 or blanket bonds in the amount of $50,000 are required by West Virginia in the form of a surety bond from a third party backer, demonstration of assets, trust fund, or cash (Kent, 2011).

New York

In 2011, New York State ranked twenty-second in natural gas marketed production (EIA, 2011). Figure 5-4 shows the marketed production of natural gas from New York State for the period 1967-2011.

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**Figure 5-3: Marketed Production of Natural Gas in WV and PA 1967-2011.** (Data for 2000 WV Marketed Production Unavailable, used average of 1999 & 2001)

*Source: Energy Information Administration*
New York State requires a $100 permit fee and financial security in the form of bonds. The bond amount is dependent on two factors, the depth of the well and the number of wells being covered by the bond (Kent, 2011). The bond amounts range from $2,500 for one well of depth less than 2,500 ft to $250,000 for a well which is greater than 6,000 ft (Kent, 2011; Davis, 2012). Blanket bonds are available in the range of $25,000-$2,000,000, depending on depth and number of wells (Davis, 2012). The schedule of bond amounts is shown below, in Table 5-2.

*Figure 5-4: Total marketed production of natural gas in NY and PA.*

*Source: Energy Information Administration*
Table 5-2: NY State Bonding Schedule, bond amounts dependent on number and depth of wells.

Bond amounts for wells in excess of 6,000 feet are based on actual costs of plugging and reclamation as determined by NYDEP, not to exceed $2 million.

Source: Interstate Oil and Gas Commission, 2013

Texas

In 2011 Texas was the largest producing state of natural gas (EIA, 2011). It produced over twice as much gas as the second largest producer (Louisiana) and five times as much as Pennsylvania. Figure 5-5 displays the total marketed production of natural gas for Texas and Pennsylvania for the period 1992-2011.
Table 5-2 displays the schedule of permit fees in Texas.

<table>
<thead>
<tr>
<th>Depth (ft.)</th>
<th>Fee ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-2,000</td>
<td>200</td>
</tr>
<tr>
<td>2,001-4,000</td>
<td>225</td>
</tr>
<tr>
<td>4,001-9,000</td>
<td>250</td>
</tr>
<tr>
<td>9,000+</td>
<td>300</td>
</tr>
</tbody>
</table>

Table 5-3: Schedule of Permit fees in Texas, dependent upon depth of well

Source: Kent, 2009

Texas’ approach to bonding is also dependent upon well depth. This approach is similar to that of New York, but goes a step further by linking bond amounts to precise depths, rather than classes of depths. Pegging bond amount to depth makes sense given the correlation between well depth and reclamation costs and risks (Davis, 2012; Mitchell & Casman, 2011; Igarashu, et al., 2010). For individual wells, the bonding rate is $2 per foot of wellbore (Kent, 2011). The amount required for blanket bonds is dependent on the number of wells, and is not pegged to
depth. Table 5-3 displays the schedule of rates for blanket bonds in Texas, as well as the bonded monies per well at the lower and upper bound of the number of wells permitted in each category.

<table>
<thead>
<tr>
<th>Number of Wells</th>
<th>Bond Amount</th>
<th>Max. Bond/Well</th>
<th>Min. Bond/Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-10</td>
<td>$25,000</td>
<td>$25,000</td>
<td>$2,500</td>
</tr>
<tr>
<td>11-100</td>
<td>$50,000</td>
<td>$4,545.45</td>
<td>$500</td>
</tr>
<tr>
<td>101+</td>
<td>$250,000</td>
<td>$2475.25</td>
<td>Approaches Zero</td>
</tr>
</tbody>
</table>

*Table 5-4: Texas Natural Gas Blanket Bonding Schedule with Maximum and Minimum amount of bonded monies per well*

*Source: Kent, 2011*

**Wyoming**

Wyoming is the nation’s third largest gas producing state (Rankings: Natural Gas Marketed Production, 2011). Wyoming has long been a leader in natural gas production but experienced a significant increase in production beginning in the early 1990s, though it has experienced a sharp drawback in the past few years, possibly due to investments being redirected to shale plays such as the Marcellus and Eagle Ford shales. Figure 5-6 displays marketed production of natural gas in Wyoming and Pennsylvania from 1967-2011.
Figure 5-6: Total marketed production of natural gas in Wyoming and Pennsylvania (1967-2011). Note that recent decline in WY production coincides with increase in PA production.

Source: Energy Information Administration

Wyoming requires individual bonds of $10,000 for wells less than 2,000 feet and $20,000 for wells greater than 2,000 feet (WYSOS, 2011). Additionally, $75,000 blanket bonds may be posted for all wells in the state, regardless of depth (WYSOS, 2011).

Oklahoma

Oklahoma was the nation’s fourth largest producer of natural gas in 2011, producing a total of 1,888,970 MMCf (EIA, 2011). Figure 5-7 displays total marketed production of natural gas from Oklahoma and Pennsylvania from 1967-2011. The data come from the Energy Information Administration.
Oklahoma requires a bond in the amount of $25,000 per well and offers blanket bonds which do not exceed $50,000 (Davis, 2012; Kent, 2011). In addition, no permit fee is required.

Alaska

Alaska currently has the highest individual bond amount in the country of $100,000. This amount was set in 1980 and has not been revised since that time (Norman, 2013). Figure 6 provides a look at historical natural gas gross withdraws from natural gas wells in the state of Alaska from 1970 to 1990, ten years before and after the implementation $100,000 bonds. The graph illustrates that contrary to experiencing a contraction upon the introduction of $100,000 bonding requirements, Alaskan natural gas production increased. The exception to this trend is seen in 1986 during a slight contraction, but this does not negate the contention that increased bonding costs would be absorbed by producers because this contraction was part of a larger, nationwide contraction.
In addition, the natural gas industry in Alaska is highly dependent on small producers. This is similar to the Pennsylvanian and national market structures (Davis, 2012). In Alaska, the median number of permits owned by an operator is just three. In Pennsylvania, the median number of permits was one in the last quarter of 2012 (AOGCC Data List, 2013; SmithBits Rig Count History, 2013). If the small-producer driven Alaskan industry can absorb these costs, I see few compelling reasons why Pennsylvania’s cannot, especially in light of the unprecedented increase in recoverable reserves in recent years in Pennsylvania (Schenk, Pierce & Demas, 2012; Pierce, Coleman & Demas, 2011).
Summary of Current Approaches by Various States

Through analyzing the various bonding policies of other gas producing and neighbor states, I can contextualize our analysis of Pennsylvania’s bonding policy. Table 5-5 displays the bonding requirements of all the states discussed above.

<table>
<thead>
<tr>
<th>State</th>
<th>Single Bond ($)</th>
<th>Blanket Bond ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pennsylvania</td>
<td>4,000-10,000</td>
<td>35,000-600,000</td>
</tr>
<tr>
<td>Ohio</td>
<td>5,000</td>
<td>15,000</td>
</tr>
<tr>
<td>West Virginia</td>
<td>5,000</td>
<td>50,000</td>
</tr>
<tr>
<td>New York</td>
<td>2,500-250,000</td>
<td>25,000-2,000,000</td>
</tr>
<tr>
<td>Texas</td>
<td>2/ft</td>
<td>25,000-250,000</td>
</tr>
<tr>
<td>Wyoming</td>
<td>10,000-20,000</td>
<td>75,000</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>25,000</td>
<td>50,000</td>
</tr>
<tr>
<td>Alaska</td>
<td>100,000</td>
<td>250,000</td>
</tr>
</tbody>
</table>

Table 5-5: Aggregate Permit fees, severance tax rates, bonding amounts, and other fees for PA, OH, WV, NY, TX, WY, and OK.

From the above discussion of various states’ approaches to ensuring environmental remediation, it is clear that few states offer incentives to operators to internalize costs. Only two states, Texas and New York, have bonding schedules which are correlated to depth of wells. This is an essential feature of internalizing costs because the costs of reclamation are strongly correlated with well depth (Davis, 2012; Mitchell & Casman, 2011; Igarashu, et al., 2010). New York’s policy of requiring bond amounts based on the estimated full cost of reclamation are most effective at incentivizing producers to perform their own reclamation activities. This is a model other states might consider adopting as it forces full cost internalization, something which severance taxes and impact fees do not achieve. The various severance taxes, permit fees, and impact fees levied by states do nothing to increase incentives provided to operators to internalize...
costs because those are taxes which must be paid regardless of whether or not an operator carries out its environmental obligations. Policies in Pennsylvania can be similarly categorized.

Pennsylvania’s approach toward natural gas bonding is, regrettably, lacking in comparison with states such as Texas and Alaska, which implement a bonding system that compels a higher degree of cost internalization than that which is induced through Pennsylvania’s regulatory framework. Pennsylvania’s recent efforts at building a nuanced legal framework to address the growing number of gas wells and gas production are to be commended. However, its efforts (and those of other states with shale plays) do not go far enough at addressing the fundamental and underlying problem in the natural gas industry: that incentives are misaligned. Taxes and fees, as they are used in the above states, do nothing to address this problem. The increased bonding amounts—while forcing some degree of increased cost internalization—still fail to induce full cost internalization. Full cost internalization, as an examination of Pennsylvania’s coal industry will show, is essential to ensuring that environmental costs are borne by those who produce them.

The question of how to fund reclamation liabilities associated with coal production has long challenged regulators and industry. Over the past two and a half decades different approaches to this issue have been attempted in the coal industry. The coal industry used two methods of meeting future liabilities and both were ill suited for their designed purpose.

In 1977, Congress enacted the Surface Mining Control and Reclamation Act (SMCRA) with the goal of protecting the environment and citizens against the harmful effects of future mining activities, as well as addressing the harmful effects which already existed (Pennsylvania Federation of Sportsmen’s Clubs, et al. v. Dirk Kempthorne, et al., No. 06-1780, 2007). The act established a federal regulatory framework which pursued these goals and was administered by the Office of Surface Mining (OSM) within the Department of the Interior. Part of the Act stipulated that mining permit applicants were required to post performance bonds for mine
reclamation and long term treatment of post-mining discharge—water which has become contaminated with heavy metals and acid as a result of mining activities. According to the SMCRA, bonds must be “sufficient to assure the completion of the reclamation plan if the work had to be performed by the regulatory authority” (Surface Mining Control and Reclamation Act of 1977, Public Law 95-87, 2012).

The SMCRA set forth two options for bonding systems. The first, the “Conventional Bonding System (CBS) required full cost, site specific bonds. The second, the “Alternative Bonding System” (ABS), allowed for less-than-full cost, site specific, bonds. In addition, the ABS drew on a statewide bond pool contributed to by operators such that operators shared the liability of reclamation. Further, the act contained provisions which allowed states to take primacy of their own regulatory programs provided they fulfilled the standards set out in the SMCRA. Pennsylvania did so.

In 1982, OSM approved Pennsylvania’s plan to manage its own regulatory program, to be administered by the Pennsylvania Department of Environmental Protection. Pennsylvania chose to implement a system in which an ABS would be used for surface coal mines and coal processing plants (Pennsylvania Federation of Sportsmen’s Clubs, et al. v. Dirk Kempthorne, et al., 2007). The bonds under this system were augmented by a statewide bond fund called the Surface Mining Conservation and Reclamation Fund (PA SMCRA Fund). Within ten years, this fund became incapable of meeting its legal responsibilities (Pennsylvania Federation of Sportsmen’s Clubs, et al. v. Dirk Kempthorne, et al., 2007).

The OSM notified PADEP in January 1991 that the ABS must be modified because it did not meet federal standards. Simply, the ABS did not have sufficient funds to meet its then-present and future expected liabilities (30 C.F.R. Sec. 983.16(h)). Later that same year, the OSM sent PADEP a notice stating that a review found, “unfunded liabilities…in excess of eight million dollars” and that “the ABS is financially incapable of abating or permanently treating pollutional
discharges from bond forfeitures” (OSM Part 732 Notice). In short, the Alternative Bonding System was not adequate to meet the existing and projected liabilities it was supposed to cover.

In 1998, a letter from PADEP stated that the agency held $89 million worth of bonds for 331 permits which had not yet been reclaimed or did not meet regulatory standards. Furthermore, the letter stated that, “the [$89 million] bonds do not represent anywhere near the amount of money required to provide for the long-term treatment…in case of default by an operator”. The letter concluded with a poignant remark on the grossly underfunded liabilities: “The dog is no longer sleeping.” (Chronology of Steps Taken by Pennsylvania and the Office of Surface Mining Reclamation and the Enforcement to Address Issues Raised by the 1991 Part 732 Notice and 30 CFR § 938.16(h), 2008) The state was compelled by the OSM to adopt a full-cost Conventional Bonding System that would “fully reflect the [PADEP’s] estimated cost for reclamation…” for future operations (Pennsylvania Federation of Sportsmen’s Clubs, et al. v. Dirk Kempthorne, et al., 2007). Past obligations still remained, however.

In a 2007 decision in Pennsylvania Federation of Sportsmen’s Clubs, et al., v. Dirk Kempthorne, et al., the Third Circuit Court of Appeals ordered that PADEP ensure that “revenues to the Surface Mining Conservation and Reclamation Fund are adequate to fulfill outstanding reclamation obligations at…forfeited sites” (Pennsylvania Regulatory Program Amendment Regarding Pennsylvania’s Defunct Alternative Bonding System as Required by 30 C.F.R. § 938.16(h) and the Part 732 Notices, 2008). These sites are referred to as legacy sites, because they were sites for which bonds had been forfeited prior to the termination of the ABS. In order to meet the requirement of ensuring perpetual treatment of the legacy sites and future sites, the State adopted a trust fund approach in which perpetual treatment was to be financed with the capital gains generated in site-specific trust funds which were invested in a mix of equity and debt instruments, as discussed previously (Small, 2009).
This approach was laden with ill-conceived and overly optimistic assumptions about future economic conditions and contained elements with absolutely little sound economic or financial justification, as discussed in Chapter 6 (Small, 2009). These coal reserves represented a nontrivial portion of the assets in the trust; of the $7.6 million in the trust, the reserves represented $4 million (Al Hamilton Treatment Trust Report, 2012).

The proper treatment of the 14 sites maintained by the Al Hamilton Trust depended on the ability of the trustee to convert coal reserves to cash and place the cash in the trust. To date, the trustee has been unable to do so. The trustee twice issued formal notice of its intent to sell or lease the reserves, in 2004 and 2007. These efforts were met with tepid interest and, since 2008, no additional effort has been made to formally market the coal reserves (Al Hamilton Treatment Trust Report, 2012). A report on the status of the trust further stated that there was little, if any, interest from industry in buying the reserves (Al Hamilton Treatment Trust Report, 2012). As a result, “the Al Hamilton Treatment Trust is experiencing severe financial stress” and by 2012 the Trust (excluding the value of reserves) was valued at only 26% of its initial value, and the cash reserves were down to 34% of their initial value (Al Hamilton Treatment Trust Report, 2012). This state of financial distress in the trust could have the effect of forcing the state to seek out additional funding for the treatment of these pollution discharges independent of the trust fund, (Al Hamilton Treatment Trust Report, 2012).

The Alternative Bonding System discussed above is similar to the bonding system currently in place in Pennsylvania’s natural gas industry in that they both allow for discounted bonds. That is, they both allow for bonds that do not cover the full cost of reclamation. According to a study conducted by the US General Accounting Office in 1986, the amount of bonded monies Pennsylvania held at the time of the study was only about 12% of the total expected costs of reclamation. Additionally, only 33% of acreage covered by forfeited bonds was reclaimed by the state. These deficiencies were credited to to inadequate bonding amounts and
legal delays in forfeiture of the bonds (GAO, 1986). If this same outcome is to be avoided in the natural gas industry, Pennsylvania must learn from its experience with coal bonding and ensure that bond amounts accurately reflect the true costs of reclamation.

Another lesson from Pennsylvania’s coal industry that can be applied to the natural gas industry is that trust funds, and more specifically systems under which a demonstration of assets is considered acceptable collateral—are not effective at funding long-term liabilities. The Al Hamilton Trust case study illustrates that the mere possession of assets is not sufficient to ensure that environmental obligations will be met. The Al Hamilton trust might have been able to meet its obligations had it been able to sell its coal reserves, but it was not able to do so, leaving a funding gap which will force society to decide between funding remediation or living with pollution—both inefficient outcomes.

In addition to setting bonding amounts below expected reclamation cost and allowing for illiquid assets to be posted in place of bonds, another reason the ABS failed is that it did not account for unexpected costs. Unexpected costs can take many forms, but in the case of mining in Pennsylvania, Acid Mine Drainage (AMD) is the largest unexpected cost faced by operators and the state (West, 2013). AMD is water which picks up high levels of iron and other heavy metals in abandoned mines and rises to the surface, often contaminating watersheds and giving streams eerie orange hues. AMD can wreak havoc on ecosystems and cost millions to clean up (Trout Unlimited, 2011).

Unexpected costs are present in the development of Pennsylvania’s natural gas industry. Be it providing potable water for a community such as in the case of Cabot Oil & Gas or cleaning up spilled fracking fluid which contaminated the Susquehanna River as in the case of Chesapeake Energy Corporation, accidents happen, and when they do, the state must be fully prepared to take swift action if operators cannot (Davis, 2012; Mitchell & Casman, 2011).
Unconventional drilling techniques are relatively new and the technology involved is evolving quickly (Davis, 2012). Combine that fact with the long life span of natural gas wells, and it becomes clear that the full extent of possible environmental damages from the development of natural gas reserves is unknown (Davis, 2012). It is not clear that the Commonwealth is prepared to finance the cleanup of the shale gas version of AMD. Bonding is especially suited for this type of catastrophe, in which the probability of an event is relatively low, but the costs to address the event are high (Boyd, 2001).

Requiring bonds in the amount of possible damages—if reliable data on expected damages existed—for each well would not be an optimal solution. However, I argue that current bond amounts are set below an optimal level to account for even routine reclamation, let alone reclamation associated with catastrophic events. If reliable data concerning the probability and damages of natural gas accidents, then an actuarially rational bond amount might be the probability of an accident occurring multiplied by the expected damages \textit{in addition to} the bond amount established for routine (i.e., probability = 1) reclamation efforts. To be clear bonds in amounts of about $100,000 would remove the misalignment of incentives where routine reclamation is concerned, and mitigate the misalignment of incentives where catastrophic events are concerned.

In this section I discussed how a coal bonding scheme similar to the one used in the natural gas industry was declared insolvent over twenty years ago, and still to this day relies on monies allocated in the state budget to offset its liabilities (Weist, 2013). In particular, I identified two key traits that the bonding schemes share in common and which can in part be credited for the failure of the Alternative Bonding System in Pennsylvania’s coal industry: discounted bonds, and the inability to absorb unexpected costs. Any bonding system which is instituted should be full cost and adjustable in order to ensure that all future liabilities will be met,
even as they arise. In the next section, I will apply lessons learned from the coal industry over twenty years ago to today’s natural gas industry.
Chapter 6
Realining Incentives: A Policy Proposal

This section will use the information presented in previous sections to motivate a policy proposal aimed at realigning incentives in Pennsylvania’s natural gas industry with regards to reclamation and environmental efforts. This proposal will use a bonding mechanism to force full cost internalization of plugging and reclamation efforts, thereby incentivizing producer performed which is full-cost, site specific and which addresses both existing and future liabilities.

Require Full Cost Bonds

The first, and perhaps most crucial aspect of this proposal is to increase the requisite bonding levels to an amount commensurate with the actual costs of reclamation. In the previous section, it was illustrated that below-cost bonding led to insolvency of the entire bonding program—this is a fate which this proposal aims to avoid. However, the current policy in place is essentially a below-cost bonding system. As such, producers are tempted to forfeit bonds and leave reclamation to the state. This condition is problematic because it not only ties up valuable state time and resources, but because the costs of reclamation are often greater than the bond amount, leaving a balance to be paid by taxpayers. Thus, the ideal bonding system will require full cost bonds in the amount of $100,000 per well, as shown in Chapter 2.

Require Individual, Site Specific Bonds

The second pillar of this proposal is to prohibit blanket bonds. While blanket bonds are relatively common throughout the natural gas industry, they serve to reduce the amount of bonded monies available for individual sites such that the amount is less than the marginal bonding rate of $10,000. Blanket bonds are used in order to pool risks presented by individual wells and keep capital free for investment. The economic justification for blanket bonds is that they are effective at incentivizing responsible behavior for firms with a small number of wells.
such that the bonded monies per well is greater than the expected costs of reclamation. This is because noncompliance on a single well risks the forfeiture of entire bond. However, incentives become misaligned when the number of wells becomes large enough such that the bonded monies per well are less than the expected costs of reclamation (Davis, 2012). In other words, as the number of wells bonded under a blanket bond increases, the amount of bonded monies per well decreases, as shown in Chapter 2. At a certain point, the average amount of money bonded per well becomes less than the expected costs of reclamation, thereby incentivizing producers to leave sites un-reclaimed.

Risk pooling is not an acceptable practice where reclamation is concerned. This is because reclamation is an inherently low-risk-tolerance endeavor, necessitating that the full amount of money needed for reclamation be available to the state in the event of bond forfeiture (Small, 2009). In place of blanket bonds, this paper proposes site-specific bonds. Site-specific bonds have two advantages over blanket bonds. First, site-specific bonds guarantee that every site has dedicated monies available for reclamation, a condition which does not currently exist under blanket bonding. Further, site-specific bonds allow for individual adjustments up or down from the base amount of $100,000 for atypical drilling operations.

One example of an adjustment which might be made is based on Andersen and Coupal’s work on well site reclamation. Andersen and Coupal (2009) calculated the cost of re-grading topsoil per acre and road removal per foot to be about $2,500 and $0.57 respectively.

One example of a formula for a model individual well bond amount might be:

\[
Bond\ amount = [100,000 + 0.62 \times (L - 10,675)] + [2,500 \times (A - 3)] + [0.57 \times (D - 400)]
\]

Where:

\(L\) = Total length of wellbore including horizontal and vertical portions in feet

\(A\) = Area of well pad

\(D\) = Distance of access road in feet
This formula is based on the average depth including horizontal portions and well pad size and distance of access road (Mitchell & Casman, 2011; New York State Department of Environmental Conservation, 2011). This formula will effectively adjust the bonding amount up or down depending on a particular project’s variation from the mean land disturbance and well depth. Thus, an average well will require a bond amount of $100,000.

Further empirical research into this area could help to determine Pennsylvania-specific figures. Currently, data concerning precise acreage and access road reclamation activity in Pennsylvania is not available. Thus, the ability to adjust bond amounts will encourage producers to select lower risk (i.e., shallower) and more environmentally responsible (i.e., less associated environmental disturbance) projects.

**Require Bond Posted as Liquid Asset**

Third, this paper advocates requiring that all financial assurance be in the form of surety bond, cash, or other liquid assets and that these instruments be held by the state treasurer. In effect, this provision would do away with the demonstration of assets system. This shifts the burden of proof from the state to the operator in the case of forfeiture. Under the current system, many operators opt to post bonds by using firm assets as collateral. The process of seizing assets and selling them can take upwards of a year due to legal challenges, beyond the time frame established for reclamation by PADEP (PAEHB, 2009). Under the proposed system, bonds would be deposited with the state, expediting the process of attachment and execution. This is preferable to the state having to prove liability through a protracted legal process, because timely response is essential to mitigating damage to the environment (Boyd, 2001).
Establish Fund for Future Liabilities

Fourth, this proposal aims to fund existing and future liabilities the state may encounter through the establishment of a statewide remediation fund which will have two sources of income. First, forfeited bonds will be placed in this fund. This fund will be maintained by the state treasurer and used to meet abdicated obligations of the private sector. Operators in good standing will be able to collect interest on the full amount of their bonds currently held by the state. However, if an operator fails to meet regulatory mandates, the stream of interest will cease, and interest will accrue to the statewide remediation fund, the fund’s second source of income. Revocable interest on bonds will serve to incentivize compliance with regulatory standards. Operators who fulfill their obligations under the law will receive steady cash flows. Should they ignore or otherwise leave obligations at any of their sites unfulfilled, these interest payments on all of their bonds for all of their sites will cease.

This approach has many advantages. First, it supplies operators with a constant, reliable stream of income in an industry that is prone to boom and bust cycles (Andersen & Coupal, 2009). In addition, the interest payments will be contingent upon the operator’s good-faith completion of reclamation efforts. In effect, these interest payments will serve as additional incentive to compliance in that the interest payments can be cancelled if firms do not fulfill their statutory obligations.

In short, the four pillars of my proposal are:

1.) Require bonds to be in amount commensurate with expected costs of reclamation
2.) Scrap blanket bonds and require site specific bonds for each drilling operation
3.) Do away with the demonstration of assets system, and require bonds be posted as cash, surety bond, letter of credit, or certificate of deposit
4.) Establish a fund using forfeited bonds and interest payments to meet unexpected, future reclamation liabilities

It is important to note the different effects that this proposal would have for different types of costs. For relatively certain reclamation costs, this proposal would eliminate the
misaligned incentives currently in place. For uncertain costs, such as those associated with blowouts or leaks, this proposal would *mitigate* the misalignment of incentives currently in place. This is a subtle but important distinction. In this light, this proposal could be viewed as a proposal for reclamation bonds. Financial assurance for catastrophic events would be difficult to assess due to lack of robust and reliable data (Davis, 2012). That is not to say that increasing the bonding amount to about $100,000 does not mitigate some of the risk the state takes on when permitting a gas well, because it certainly does.

In this section I detailed four points which I believe should serve as the basis for a bonding program in Pennsylvania’s natural gas industry. I believe that by requiring full-cost, site-specific, and liquid financial assurance and allowing interest to accrue to operators engaged in best practices will accomplish three critical goals not being addressed under the current system. First, firms will internalize the entire cost of reclamation, thereby allocating resources in a more socially efficient manner. Second, in the event of operator insolvency or absence, the state will have an appropriate amount of funds immediately available to undertake reclamation efforts. Third, the proposed system will generate income which can be used to meet existing and future liabilities. In the next section I will address a number of potential problems with the proposed policy as well as present alternatives to a bonding system which I ultimately deem inadequate in order to further demonstrate the appropriateness of a bonding solution to the problem of misaligned incentives.
Chapter 7

Conclusion

Over the next three decades, over three hundred thousand acres of pristine farmland and forest could be disturbed in the process of procuring natural gas in Pennsylvania (Mitchell & Casman, 2011). It is essential to the health of the current and future generations that these disturbed lands are restored to states as near to their original condition as possible. Because the lifespan of a gas well is decades long and the Marcellus boom is still in its early stages, the full magnitude of the effects of the current incentives in place may not be felt for many decades (Davis, 2012; Mitchell & Casman, 2011). In order to avoid environmental damages, it is important to address this issue as soon as possible, before additional effects of the misaligned incentives take effect.

The Marcellus Shale play provides opportunity for significant economic benefits to the private sector, and as it stands, significant liabilities to tax payers. These liabilities include the costs of site reclamation and well plugging. In order to promote cost internalization, bonds are often used. However, current guidelines require bonding amounts that are far too low to accomplish their stated goal of internalizing costs. In order to promote full cost internalization, this paper proposes increasing bonding amounts to full cost, as well as implementing a strictly site specific bonding program in order to ensure that each site has dedicated funds available in case an operator is unable to perform reclamation duties.

Critics of bonding mechanisms point out that it will be problematic to require full cost bonding in a market dominated by small interests. Two cases seem to present evidence to the contrary: Alaska’s 1980 adoption of full cost bonding, and the development of a robust and
reliable financial assurance market for vessels in response to the Oil Pollution Act of 1990. In addition, bonding alternatives have many flaws, such as market uncertainty leading to insolvency as was seen in Pennsylvania’s coal mining industry.

Through full cost and site-specific bonding, the issue of misaligned incentives is remedied and insolvent, judgment proof, or otherwise unavailable operators will not be a financial burden on tax payers. The proposed policy addresses past, present, and future liabilities in a socially efficient, environmentally responsible, and financially sound manner.
<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Unit Price</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Item 1</td>
<td>$100</td>
<td>200</td>
</tr>
<tr>
<td>2</td>
<td>Item 2</td>
<td>$200</td>
<td>400</td>
</tr>
<tr>
<td>3</td>
<td>Item 3</td>
<td>$300</td>
<td>600</td>
</tr>
</tbody>
</table>

**Notes:**
- Item 1 is provided in packs of 5.
- Item 2 is available in bulk quantities.
- Item 3 requires specific installation by a licensed electrician.
Appendix B

Financial Ratio Tests

An applicant should meet at least three of the following four ratio requirements.

a. \[
\frac{\text{Current liabilities}}{\text{Net worth}} < 1.0
\]

and

\[
\frac{\text{Long term liabilities}}{\text{Net worth}} < 2.0
\]

b. \[
\frac{\text{Current assets} \less \text{Current liabilities}}{\text{Total assets}} > -0.10
\]

c. \[
\frac{\text{Net income plus depreciation, depletion and amortization}}{\text{Total liabilities}} > 0.10
\]

d. \[
\text{Net profit} > 0
\]

To demonstrate that he passes this test, the applicant submits the information described in Section E under the financial statement coverage option. Initially he should submit data only for the latest fiscal year. Only when he fails the test for that year should he submit the data for the previous two years. Upon failing the test or being disallowed from using the test, the owner or operator should provide a bond or other financial instrument for a coverage amount specified by EPA.

If an operator is a subsidiary of a large corporation, the financial statements of the parent corporation may be submitted if the parent also guarantees that it will provide funds sufficient to plug the subsidiary's wells. Such a guarantee should be from a parent that directly owns at least 50% of the operator's voting stock. The parent corporation is bound by the guarantee until released by EPA. If the subsidiary is audited as a separate entity, its financial statements may be submitted.

Source: EPA National Library Catalog
EPA 570/9-84-007
Appendix C

Description of PADEP’s Volatility Multiplier

Using Pennsylvania’s assumptions:

\[ PV_{\text{out}} = \left[ (A/0.0843) + A \right] \times 1.16 \]
\[ = \left[ (A/0.0533) + A \right] \times 1.16 \]
\[ = \left[ 18.7617A + A \right] \times 1.16 \]
\[ = \left[ 19.7617A \right] \times 1.16 \]
\[ = 22.9236A \]

Assumed rates of return by themselves result in annual cost multiplier of 19.7617. Volatility multiplier (1.16) changes the annual cost multiplier from 19.7617 to 22.9236.

Q: If there were no volatility multiplier, what rate of return would produce an annual cost multiplier of 22.9236?

where \( x \) = the net real rate of return (0.0533) in the example above

\[ 22.9236A = 21.9236A + A \]
\[ 22.9236A = A/x + A \]
\[ 21.9236 = A/x \]
\[ 21.9236 - 1/x \]
\[ x = 1/21.9236 \]
\[ x = 0.0456 \]

So, using 3.1% inflation rate, the net nominal rate of return is 7.66% (the parallel to the 8.43% net rate of return Pennsylvania assumes).

In turn, adding in the 1.5% trust fee assumed by Pennsylvania, the 7.56% net nominal rate of return translates into a gross nominal rate of return of 9.16% on the trust portfolio (the parallel to Pennsylvania’s assumed portfolio return of 9.93%).

Overall, the effect of Pennsylvania’s volatility multiplier is the same as reducing the portfolio’s gross nominal rate of return from 9.93% to 9.16%, and the net nominal rate of return from 8.43% to 7.66%.

Source: Small (2009) Appendix II


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Education


Honors and Awards

- Quentin and Louise Wood Trustee Scholarship, June 2011 & 2012
- Schreyer Honors College Student Ambassador Scholarship May 2011 & 2012
- Hess Corporation Scholarship, July 2011
- Penn State Academic Competitiveness Grant, July 2010

Association Memberships/Activities

- Penn State Investment Association

Research Interests

I am particularly interested in the interplay between the law, finance, and economics.

Publications and Papers
