A Review of the Economic Factors Surrounding the Capture of Methane from Oil and Natural Gas Development on Federal Public Land

Research Paper

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Executive Summary

The Department of the Interior is working to address natural gas waste from oil and gas development on Federal and Tribal lands. The Government Accountability Office (GAO) (2010) estimated taxpayers lose as much as $23 million royalty revenues each year when natural gas is wasted.

The Bureau of Land Management (BLM) has responded to these problems by proposing to revise federal oil and gas rules in order to bring them up to date with current technology, reduce natural gas waste and provide a fair return on public resources for taxpayers. The proposed rule would limit losses of gas through venting and leaks from well drilling, completions and workovers, production testing, pneumatic controllers and pumps, storage tanks, liquids unloading, and leak detection and repair (LDAR). The proposed rule would also prohibit venting of gas except in certain circumstances, and would limit gas flaring during normal production operations from developmental oil wells.

The BLM estimated the costs of the rule to include direct compliance costs and the social cost of the carbon dioxide generated. Given that methane is a large component of natural gas, reducing methane pollution will significantly benefit the guidelines to reduce natural gas waste. Methane is a greenhouse gas about 25 times more potent than carbon dioxide over a 100-year timeframe but even more potent (86 times) over 20-year timeframe. Methane pollution accounts for nine percent of all U.S. greenhouse gas emissions and almost one-third of that is estimated to come from oil and gas operations (BLM 2016). The benefits, as calculated by the BLM, include the direct cost savings from recovered gas and the social benefit of methane reductions. Net benefits, calculated as the benefits minus the costs to range from $115 to $188 million per year based on a 7% discount rate and $132 to $238 million per year based on a 3% discount rate (Table 1).

While the BLM utilized many possible benefits when completing the benefit cost analysis (BCA), the agency did not include the many co-benefits generated by implementing the methane capture rule. These co-benefits occur because the methane capture requirements also reduce air pollution from volatile organic chemicals (VOC), fine particulate matter (PM) and other hazardous air pollutants (HAP). If these non-monetized co-benefits had been included in the BCA -- the net benefits from the rule would be significantly greater.

The BLM's analysis indicated that at the economic margin – the cost of complying with the methane capture rule is small. These results are consistent with our review of the economic literature: the cost of complying with environmental regulations is not a huge cost burden. The reasons for this include: 1) regulatory compliance costs are small relative to total business costs; 2) comparable regulations exist across state lines and from country to country; 3) other economic factors like drilling and labor costs play a more significant role in location decisions; and 4) technological change stimulates innovation and increases productivity which offsets the costs of regulation.

Table 1. Estimated Annual Net Benefits with EPA Finalizing its Rule. 2017 – 2026 (Millions of $).[2]

Requirement	7% Discount Rate	3% Discount Rate	Non-Monetized Benefits
Flaring	($11) - $7	$12 – 28	Health effects of PM2.5 and ozone exposure from annual VOC reductions;
Well Completion	$1 – 2	$1 – 2	
Pneumatic Controllers	$53 – 68	$54 – 73	Non-monetized climate benefits;
Pneumatic Pumps	$17 – 23	$17 23	Health effects of reduced HAP exposure;
Liquids Unloading	$35 – 52	$35 – 55	Visibility benefits
Storage Tanks	$2 – 5	$2 – 5	
LDAR	$19 – 43	$20 – 48	Ozone effects on crops and forests
Administrative Burden	($2 – 3)	($2 – 3)	Incremental environmental benefits of combusting gas downstream.

Source: Adapted from BLM 2016

The treatment of technological change is increasingly recognized as an important variable when estimating the benefits and costs of environmental regulations. We find the BLM's revised rules for capturing methane to be well designed to spur continued technological innovation and increased productivity in the oil and gas industry. Our review of the literature also provides evidence that the oil and natural gas industry has much to gain by embracing and perhaps exceeding the BLM's methane capture rule.

The San Juan Basin is a natural gas and oil producing region currently impacted by the low price environment of the bust phase of the boom and bust cycle. We conducted a case study of two counties in the San Juan Basin of northwest New Mexico to better understand regional impacts of the BLM's proposed methane capture rule and focus on natural gas wells as it is the dominant fossil fuel produced in the region. We completed a Net Present Valuation of the costs of complying with proposed LDAR requirements and the new revenues from the methane captured. Based on this analysis we estimated the change in overall gas production and associated royalty payments to the state. We examined 13,493 active federal gas wells in these two counties and determined that 8,718 (65%) of these wells produced less than 90Mcf per day (Table 2).

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[2] In 2015, the EPA published a Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector.

Table 2: San Juan and Rio Arriba County Federal Marginal Gas Wells

Amount per production day	Number of Wells in 2015*	Percent of Total Wells	Total 2015 Production (MMcf)	Percent of Total Production
Wells with less than 15mcf	1,360	10%	3,682	0.85%
Wells with less than 30mcf	3,082	23%	16,608	3.85%
Wells with less than 60mcf	6,311	47%	66,032	15.29%
Wells with less than 90mcf	8,718	65%	128,634	29.79%
Total**	**13,493**	**100%**	**431,776**	**100%**

*Active, Federal wells only with greater than10 days of production in both 2014 and 2015, and greater than zero amount produced in both 2014 and 2015.
**Totals include all marginal and non-marginal wells. Marginal well categories are cumulative and do not add up to the total.
Source: New Mexico Oil Conservation Division: http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx.

Assuming markets recover in three to four years, we estimate that the majority of marginal gas wells will not only reduce methane emissions and natural gas waste, but by capturing the methane for sale, profits will also increase as a result of the proposed rule.[3] Our analysis indicates that only very marginal gas wells that produce less than 15Mcf/day have a negative return, but the net costs (compliance cost minus new revenue) for these producers is quite small, about $1,000 annually for the first few years. This suggests a small increase in overall costs, and a minimal increase in net costs for just the smallest wells.

We estimated three scenarios of the economic effect of the methane rule on San Juan Basin royalties to the state of New Mexico. Our analysis indicates under all of the scenarios, that complying with the methane rule would have a small, positive effect on production and royalties in the San Juan Basin. This is consistent with the literature and with the BLM's findings in the RIA. We view the proposed LDAR compliance overall effect on production and royalties to be negligible in the San Juan Basin.

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[3] The U.S. Energy Information Administration (2016) forecasts natural gas prices to increase in the future: nearly doubling in the next 18 months.

Introduction

The Obama Administration's efforts to address climate change include strategies to reduce natural gas waste and methane pollution associated with oil and gas development on Federal public land. The Bureau of Land Management (BLM) under the Mineral Leasing Act of 1920 is required to "use all reasonable precautions to prevent waste of oil or gas developed…"

Between 2009 and 2014, oil and gas producers on public and Indian lands vented, flared and leaked about 375 billion cubic feet (Bcf) of natural gas. Methane is a greenhouse gas about 25 times more potent than carbon dioxide over a 100-year timeframe but even more potent (86 times) over 20-year timeframe. Methane pollution accounts for nine percent of all U.S. greenhouse gas emissions and almost one-third of that is estimated to come from oil and gas operations (BLM 2016). In addition to methane pollution, the Government Accountability Office (GAO) (2010) estimated taxpayers lose as much as $23 million royalty revenues each year when natural gas is wasted.

The BLM has responded to these problems by proposing to revise federal oil and gas rules, bringing them up to date with current technology, in order to reduce methane waste and provide a fair return on public resources for federal taxpayers, Tribes, and States. In January 2016, the BLM published a Regulatory Impact Analysis (RIA) for the revised rules as required by the Office of Management and Budget (OMB). Guidance from OMB requires regulatory impact analysis to do four things: state the need for the regulation, discuss alternatives, assess benefits and costs of each alternative, and explain why the proposed regulation is the preferred alternative (Harrington and Morgenstern 2004). For our purposes, we will focus on the assessment of the benefits and costs of reducing air pollution by capturing more methane from oil and natural gas development.

This analysis is based upon the draft regulatory requirements released by the BLM in January 2016 and does not reflect recommended changes being made to the rule by either industry or conservation groups. We begin our white paper with a brief summary of the economic tools available for evaluating the revised rule. We then evaluate the new rule based on a review of the BLM's Regulatory Impact Statement and relevant literature. In order to gain some understanding of the effect on gas operators we present a case study of the San Juan Basin of New Mexico. We end with a brief summary of our results.

Background

Methane pollution represents an inefficient use of a valuable resource.   A principle of current welfare economics is that markets are efficient only if all market and nonmarket costs are fully reflected in market price[4]. An environmentally and fiscally responsible oil and natural gas

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[4] Market costs include the things we normally associate with oil and gas, such as the cost of drilling rigs and materials used during drilling, the labor costs of work crews, interest on borrowed capital, and so on. These market costs are paid directly as a matter of course by oil and gas producers. In addition to these normal expenses, oil and gas production results in environmental and social costs not part of normal business expenses. These indirect nonmarket costs include water and air pollution, the negative impacts on communities from noise and truck traffic, adverse health effects, impacts on wildlife, and other costs not paid directly by oil and gas producers. Called "negative externalities" by economists, these costs are external to oil and gas producers, but are still very real and paid indirectly by someone other than oil and gas producers (Morton 2012, Morton and Kerkvliet 2014).

program strives to promote efficient energy markets that account for the social and environmental costs in prices and the energy supply curve (Morton and Kerkvliet 2014). However, market failure occurs when non-market costs, such as methane pollution, are not reflected in market prices. Markets fail to maximize net benefits when negative externalities exist.

The polluter pays principle is based on sound environmental economics, will lead to more efficient markets and is a guiding principle for implementing responsible oil and gas development. The polluter pays principle (PPP) simply says that oil and gas companies will pay all of the direct market and indirect non-market costs of producing oil and gas. Internalizing environmental externalities is the main objective of the polluter-pays principle. Economists believe that only when external costs have been fully considered will firms act so as to prevent market failures and move to a socially optimal level of output. Using the PPP, prices account for all of the direct and indirect costs of producing oil and gas.

As noted by the BLM (2016):

> When gas is wasted rather than captured and brought to market, society loses out on the ability to consume the resource and social benefits are not maximized. In addition, when the wasted gas in question comes from the Federal or Tribal mineral estate, the public or Tribes are often not compensated for the loss if royalty is not assessed. Additionally, state governments do not receive the compensation they are owed through royalty sharing from Federal production.

> Wasting gas also produces air pollution, which imposes costs to society that are not reflected in the market price of the gas. Gas that is vented to the atmosphere or flared contributes greenhouse gas (GHG), volatile organic compound (VOC), and hazardous air pollutant emissions that have negative climate, health, and welfare impacts. These uncompensated costs to society are referred to as negative externalities.

> Several market inefficiencies occur when society rather than the producer bears the costs of pollution damage. Since the damage is not borne by the producer, it is not reflected in the market price of the commodity, and uncontrolled markets produce an excessive amount of the commodity, dedicate an inadequate amount of resources to pollution control, and generate an inefficiently large amount of pollution. With stock pollutants, like methane and carbon dioxide, which build up in the environment and cause damage over time, the burden will be greater on future generations. Further, the fact that operators do not always bear the full costs of production introduces perverse incentives to the market. Operators that voluntarily make investments to limit or avoid the loss put themselves at a competitive disadvantage in relation to operators who do not make such investments.

Under the polluter pays principle (PPP) oil and gas producers will pay for the non-market costs of the environment and social damages that occur as part of their business operations. Payments are made in many forms, including compliance costs, pollution taxes, assurances bonds, and direct in-kind services for the repair of roads.

Benefit Cost Analysis

When evaluating the pros and cons of environmental regulations, economists traditionally complete a benefit cost analysis. Benefit cost analysis is a standard economic tool for comparing the market and non-market benefits of regulations with the costs that must be incurred to secure those benefits. Economists use benefit cost analysis to examine whether oil and natural gas production results in the largest possible benefit for society – or optimal economic efficiency. As Field and Field (2009) point out, "Benefit-cost analysis is for the public sector what a profit-and-loss analysis is for a business firm" (p. 118). Economic efficiency takes the perspective of all of society, and examines all the costs and benefits associated with oil and natural gas production, including nonmarket values (Morton et al. 2015)[5].

Strategically in 2013, the BLM issued guidance for considering nonmarket environmental values when preparing NEPA analyses for BLM resource management planning and other decision-making[6]. From the document (BLM 2013):

> All BLM managers and staff are directed to utilize estimates of nonmarket environmental values in NEPA analysis supporting planning and other decision-making where relevant and feasible, in accordance with the attached guidance…The use of quantitative valuation methods should contribute to the analysis of one or more issues to be addressed in the environmental analysis supporting planning or other decision-making. A quantitative analysis of nonmarket values in EIS-level NEPA analyses is strongly encouraged where one or more of the criteria described in the attached guidance apply.

In order to comply with the spirit of the law the BLM must include the hidden environmental and social costs of burning oil and natural gas in the benefit cost analysis of the propose methane capture rule.

Net Present Value Analysis

Net present value analysis examines the discounted value of future revenue and compares them with the discounted costs associated with production. Companies invest in oil and gas operations expecting future cash flow from production revenues. Assessing the current value of production revenues requires consideration of the time value of money which is reflected in the discount rate. Discounting future revenue with a discount rate is the reverse of compounding today's money with an interest rate (Rose 2001). A positive NPV suggests a good investment. Key variables in the NPV analysis include, estimated production levels for each year, expected well head prices for oil and gas, exploration, development and operating costs, taxes, and the discount rate chosen (Rose 2001).

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[5] The U.S. Environmental Protection Agency (EPA) published its "Guidelines for Preparing Economic Analyses" (U.S. EPA 2014) that is a standard reference for the benefit cost analyses required by the Office of Management and Budget.

[6] The National Environmental Policy Act (NEPA) requires federal agencies to examine the environmental effects from proposed actions by producing an Environmental Impact Statement (EIS).

Economic Impact Analysis

Economic impact analysis is an attempt by economists to estimate the additional (marginal) economic contribution a given investment, policy or project may make to the existing economy. Economists rely on an Input-Output (I-O) framework to estimate the jobs associated with oil and gas development as part of an economic impact analysis. Adaptive I-O frameworks used in economic models such as IMPLAN and REMI are used to estimate the direct, indirect and induced jobs associated with changes in oil and gas policies. Direct jobs are created by direct hiring to perform the activity (i.e. drilling); indirect are jobs created by spending to support the work of direct jobs (e.g. pipe used by drillers to drill wells); and induced jobs are created when direct and indirect job holders spend their wages. So, jobs in the drilling pipe industry are indirect jobs, while bar and restaurant workers are induced jobs.

While economic impact analysis is a common tool for estimating jobs, decision-makers would do well to better understand the assumptions and limitations of the I-O framework behind the studies. Importantly, static I-O models such as IMPLAN do not consider the long term economic costs associated with the resource curse.[7] IMPLAN is a tool for estimating jobs in the short run while the resource curse is a long run economic phenomenon.

Methane Rule Economic Summary

The proposed rule would limit losses of gas through venting and leaks from well drilling, completions and workovers, production testing, pneumatic controllers and pumps, storage tanks, liquids unloading, and leak detection and repair (LDAR) (BLM 2016). The proposed rules would also phase in over several years, limits on the venting and flaring of produced natural gas. Specifically, the proposed rule would prohibit venting of gas except in certain circumstances, and would limit gas flaring during normal production operations from development oil wells to 7,200 Mcf/month (on average, per well, across all of the producing wells on a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well for the second year of the rule's implementation, and 1,800 Mcf/month/well thereafter.

The Net Benefits Generated by the Rule Are Positive

The BLM estimated the costs, benefits and net benefits for each of the proposed requirements. The costs include direct compliance costs and the social cost of carbon dioxide generated. The benefits include the direct cost savings from recovered gas and the social benefit of methane reductions. Net benefits are calculated as the benefits minus the costs (BLM RIA page 32). We applaud the BLM for including the social costs of carbon and the social costs of methane[8]. The BLM estimates that the overall benefits of the rule exceeded the costs – with net benefits ranging from $115 to $188 million per year based on a 7% discount rate and $132 to $238 million per year based on a 3% discount rate (Table 1)[9].

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[7] Many academic studies (e.g. Papyrakis, E. and R. Gerlagh 2007, James and Audland 2011) have found that economies relying heavily on natural resource extraction are poor performers in terms of growing income, decreasing poverty, and improving lives. This poor performance has become known as the "resource curse".

[8] The social costs of methane were estimated based on research by Marten et al. (2015), while the social costs of carbon dioxide were estimated using the results from the U.S. Governments Interagency Working Group on Social Cost of Carbon (2013).

[9] The results presented assume that the EPA finalizes its own rule of oil and gas emissions (EPA 2015).

The BLM did not include the co-benefits to public health from reducing VOC pollution or other hazardous air pollutants associated with oil and gas development. These co-benefits occur because the methane capture requirements also reduce air pollution from volatile organic chemicals (VOC), fine particulate matter (PM) and other hazardous air pollutants (HAP) (EPA 2015). The BLM quantified the amounts of the pollution prevented but did not monetize them in the BCA. A partial list of the non-monetized benefits includes: 1) health benefits from lower levels of ozone and HAP; 2) reduced incidence of premature mortality and morbidity from exposure to particulate matter; 3) benefits from increased in visibility for visitors to public land and citizens living in residential areas; and 4) benefits to crop yields and forest growth from lower levels of ozone (EPA 2015, BLM 2016). It bears repeating: if these non-monetized co-benefits from implementing the methane capture rule were included in the BCA -- the net benefits from the BLM methane capture rule would be significantly greater.

Table 1. Estimated Annual Net Benefits with EPA Finalizing its Rule. 2017 – 2026 (Millions of $)

Requirement	7% Discount Rate	3% Discount Rate	Non-Monetized Benefits
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Well Completion	$1 – 2	$1 – 2	
Pneumatic Controllers	$53 – 68	$54 – 73	Non-monetized climate benefits;
Pneumatic Pumps	$17 – 23	$17 23	Health effects of reduced HAP exposure;
Liquids Unloading	$35 – 52	$35 – 55	Visibility benefits
Storage Tanks	$2 – 5	$2 – 5	Ozone effects on crops and forests
LDAR	$19 – 43	$20 – 48	
Administrative Burden	($2 – 3)	($2 – 3)	Incremental environmental benefits of combusting gas downstream.

Source: Adapted from BLM 2016.

[Summary of LDAR and Flaring Requirements](#)
The LDAR requirements specify that inspections must be conducted twice a year using optical gas imaging (OGI) (such as an infra-red camera), instrument-based monitoring devices approved by the BLM; or a portable analyzer device, assisted by audio, visual, and olfactory (AVO) inspection (BLM 2016, page 103). Further, operators with more than 500 wells within a

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For simplicity in presentation, we summarize the BLM's results assuming the EPA finalizes and adopts its own rule.

single BLM field office, must use a BLM-approved OGI or another instrument-based monitoring device to detect methane leaks.

The BLM (2016) estimates that the proposed semi-annual LDAR requirement would result in net benefits of $19 –48 million per year, depending on the year. The key variables in the analysis of LDAR requirements include natural gas production rates, the leakage rate, the capture rate, future natural gas prices, and compliance costs.

Compliance costs include the costs of inspection and the costs of repairing the leak once found. Carbon Limits (2014) using primarily data from Canada, completed an NPV analysis of LDAR for wells pads and batteries[10]. The first analysis compared the repair costs with the value of gas captured and sold. In almost all cases the NPV was positive: the value of the captured and sold gas exceeded the cost of repairing methane leaks. Their results indicate that the vast majority of the leaks are economic to repair, when the value of gas is $3/Mcf or higher.

Carbon Limits (2014) completed a second analysis examining the full program cost which includes the survey-inspection along with the repair costs.   When the inspection costs are included, the majority of facilities have negative NPVs. However, as noted by Carbon Limits (2016): "…this review suggests that the results of the analysis performed in this study may be conservative when considering US facilities, since the facilities in the database were subject to ongoing LDAR surveys. Therefore, the abatement costs presented in this report are considered to be higher than the expected abatement cost for reducing emissions from US facilities where LDAR is not currently in place." In addition, "At US facilities, LDAR programs are not generally in place, and thus current leaks are expected to be larger than at the facilities in our database" (Carbon Limits 2014). What this means is that larger leak rates in the US will produce more revenue from the captured methane. All of which suggests that the number of negative NPV for LDAR will drop while the number of positive NPVs will increase when using data more representative of U.S. wells.

Since the NPV for repairing leaks is positive, the key to improving the NPV for total LDAR compliance costs is to reduce the costs of inspections over time. By decreasing detection costs over time, operators can benefit from efficiency gains and higher NPVs. In fact, evidence from Encana in the Jonah field of Wyoming shows declining inspection costs, underscoring the potential benefits from technological gains in leak detection (Encana 2014)

The primary means to avoid flaring of associated gas from oil wells is to capture, transport, and process that gas for sale, using the same technologies that are used for natural gas wells. While industry continues to reduce the cost and improve the reliability of this technology, it is long-established and well understood. The capture and sale of associated gas can pay for itself where there is sufficient gas production relative to costs of connecting to or expanding existing infrastructure (BLM 2016, page 46)

In addition to current technologies, entrepreneurs are developing new technologies designed to capture smaller amounts of gas and put them to productive uses where building a pipeline to connect to the market is impractical. Emerging technological solutions include: separating out

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[10] Well batteries include equipment on site in addition to the well head (e.g. an oil/liquids storage tank, and/or separator, etc.).

natural gas liquids (NGL) and trucking them off location; gas to liquid (GTL), a process which converts the gas into synthetic crude oil; using the gas to run micro-turbines to generate power; and using small integrated gas compressors to convert the gas into compressed natural gas (CNG) that can be used on-site or trucked off location for use as transportation fuel or conversion to chemicals (BLM 2016). Adopting the flaring rule will help push these emerging technological innovations into the marketplace.

The BLM (2016) estimates the proposed flaring requirement using currently available technology would increase natural gas production as well as the production of natural gas liquids resulting in net benefits ranging from \$13 – 30 million per year (present value calculated using a 3% discount rate) (page 60). The key variables in the analysis of the flaring requirement include oil and gas production rates, future oil and gas prices, and the distance to a pipeline.

Impacts on Small Companies

To examine the economic impact of the rule on small entities, the BLM performed a screening analysis for impacts on a sample of small entities by analyzing the potential impact on profit margins. For the 26 companies in the screening analysis, the proposed rule's estimated compliance costs would reduce the entities' profit margin, on average, by 0.104 percentage points if the EPA does not finalize its own methane capture rule, or 0.087 percentage points if the EPA does finalize its rule. Based on this information, the BLM concludes that the proposed rule would not have a significant impact on a substantial number of small entities.

The marginal costs of complying with the BLM methane capture rule are small relative to overall revenues and costs and are unlikely to be the cause of wells shutting in. The BLM (2016, page 152-3) concluded, "We generally believe that the cost savings available to operators would exceed the compliance costs or that the compliance costs would not be as significant as to force the operator to prematurely abandon the well."

The results of the BLM RIA are consistent with the recent rulemaking in Colorado. Colorado's Air Quality Control Commission (2014) estimated a net cost to industry of implementing the new air quality rules of \$42.4 million per year representing approximately 0.4% of industry's annual revenues. The Commission concluded:

> Given this small percentage, the Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole. This conclusion is bolstered by the fact that several of the largest oil and gas companies in the state (Anadarko Petroleum Corp., Noble Energy, Inc., Encana Oil and Gas USA, and DCP Midstream) fully support the Division's proposed revisions (page 38).

BLM Exemptions for Marginal Wells

Despite the relatively small compliance costs, the BLM's RIA included exemption clauses for requirements if compliance would force the operator to abandon the well. For marginal wells, the proposed LDAR requirements provide operators with flexibility for reducing the costs associated with compliance (BLM 2016).

> The operator may conduct a comprehensive inspection program that uses instrument-based monitoring devices or alternatively rely on continuous

emissions monitoring that matches the operator's abilities and programs in place, if so approved by the BLM. Additionally, for operators with fewer than 500 wells within a BLM field office, the BLM drafted a provision that would allow the use of less expensive leak detection tools. The intent of this provision is to limit the requirement to use more costly instrument-based methods to larger operators with more wells over which to spread the costs of the required inspections.

With respect to marginal wells and flaring requirements, the BLMs revised rules actually provides two exemptions from the rule (BLM 2016).

1. The BLM may approve an alternative flaring limit above those specified if the operator demonstrates that the specified limits would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease.

2. The BLM would also provide a renewable, two-year exemption from the flaring limits to operators of existing wells that are located at least 50 miles from the nearest gas processing facility, and are flaring at least 50% above the specified limit.

With these above LDAR and flaring exemptions, the likelihood of marginal wells shutting down because of the methane capture rule becomes even lower.

The Results in the BLM RIA are Consistent with the Peer Reviewed Literature.

The analysis included in the BLM RIA indicated that at the economic margin – the cost of complying with environmental regulations is small and certainly not a huge cost burden. The following review is not comprehensive but we do cite comprehensive reviews of the literature that strongly suggests that the BLM's RIA results are consistent with the economic literature. Our review of the literature also provides evidence that the oil and natural gas industry has much to gain by embracing and perhaps exceeding the BLM's methane capture rule.

In a study published in the Journal of Economic Literature, Jaffe et al. (1995) examined two decades of research looking for a negative impact from environmental regulations and concluded: "studies attempting to measure the effect of environmental regulations…have produced estimates that are either small, statistically insignificant, or not robust to test model specifications." Reasons for this somewhat counterintuitive result include: 1) regulatory compliance costs are small relative to total business costs; 2) comparable regulations exist across state lines and from country to country; and 3) other economic factors like labor costs play a more significant role in location decisions.

These retrospective results are consistent with the "Porter Hypothesis" offered by a Harvard business professor. According to Porter (1991) and Porter and van der Linde (1995), environmental regulations provide firms with an incentive to innovate and develop more cost-effective methods of achieving regulatory compliance. As a result of investing in innovation, companies may also discover new technologies that reduce both pollution emissions and production costs.

Regulations that are designed to push technological innovation and increase productivity will help offset the costs of regulations and in some cases can actually lead to increased profits. The basic idea is that with technological change, the near term costs of regulation can be offset

in part or in full, if in the long term environmental regulations stimulate innovation and increase productivity (Brannlund and Lundgren 2009).

Ambec et al. (2011) in a 20-year retrospective look the Porter Hypothesis concluded:

> This paper has provided an overview of the key theoretical and empirical insights on the (Porter Hypothesis) to date. First on the theoretical side, it turns out that the theoretical arguments that could justify the (Porter Hypothesis) are now more solid than they appeared at first…On the empirical side, on one hand, the evidence about the "weak" version of the hypothesis (stricter regulation leads to more innovation) is also fairly well established. On the other hand, the empirical evidence on the strong version (stricter regulation enhances business performance) is mixed, with more recent studies providing more supportive results.

The treatment of technological change is increasingly recognized as an important variable when estimating the benefits and costs of environmental regulations. We find the BLM's revised rules for capturing methane to be well designed to spur continued technological innovation in the oil and gas industry. And capturing more methane leads to increasing productivity.

We reviewed three peer-reviewed publications of regulatory impacts and the oil and gas industry and all three showed support for the Porter Hypothesis. In a peer-reviewed study of environmental regulations and oil refineries, Berman and Bui (2001) found that in meeting more stringent environmental standards, oil refineries in the Los Angeles air basin actually increased their productivity and efficiency. The increase in productivity was a result of "a careful redesign of production processes induced by the need to comply with environmental regulations." A second study using data from offshore oil and natural gas production in the Gulf of Mexico, found that environmental regulation did in fact induce technological change in the oil and gas industry (Managi et al. 2005).

A third study by Ford et al. (2014) found support for the Porter Hypothesis and the traditional top-down view of oil and gas regulations in Australia. Their results reveal that a high regulatory burden relates strongly to product and service innovations as well as all types of novel innovations. Ford et al. (2014) found that technological innovation is simultaneously related to a high regulatory burden and the presence of competitive capabilities, collaborative activity and research and development (R&D). According to their economic model, it is the presence of all of these factors in tandem which explain technological innovation in Australia's oil and gas industry.

The results from two additional studies are relevant to the oil and gas industry. Hart and Ahuja (1996) found a positive relation between emission reductions and firm performance. The biggest bottom line benefits accrue to the 'high polluters' where there are plenty of low-cost improvements to be made. Their results suggest that the marginal costs of reducing emissions seldom exceed marginal benefits.

Also of interest is a recent study by Lucas, M.T and T.G Noordewier (2016) that asked the question "what are the circumstances under which it might pay to be green?" Among the results, the authors found that within dirty and non-proactive industries there is a positive marginal effect on firm performance as a result of engaging in environmental management practices. Moreover, the effect on financial performance of implementing environmental management practices is

greater in relatively dirty and non-proactive industry contexts than in relatively clean and proactive industries.

Despite these examples, the oil and gas industry has been somewhat reluctant to embrace change by investing in technological innovation. As summarized by Perrons (2014):

> Future oil and gas resources—especially in non-OPEC countries—will tend to be deeper, harder to find, and in environments that are significantly more difficult to access than they used to be (Managi et al. 2004, 2005b; Hinton,2010). Second, high- profile disasters… like the recent Deepwater Horizon accident (Flournoy, 2011; Perrons,2013) have brought about a marked change in the expectations placed upon oil and gas companies with regard to environmental stewardship, safety, and human welfare (Mirvis, 2000; Managi et al.,2005a; Hofmeister,2010). In the face of these kinds of challenges, technology will clearly play a pivotal role in the success or failure of tomorrow's oil and gas firms (Longwell, 2002; Mitchell et al.,2012). Despite the strong case for technology, however, the industry has a reputation for being slow to develop and adopt innovations…
>
> The sector has accordingly been characterized in the literature as "slow clock speed" (Fine, 1998, p.239), "low-and medium-tech" (von Tunzelmann and Acha,2006, p. 408), and "technologically timid" (Lashinsky,2010, p.88). Oil & gas producers have also been categorized as "low R&D intensity" because they have historically invested less than 1% of their net revenue in research and development (R&D) (von Tunzelmann and Acha, 2006; Moncada-Paternò-Castelloetal.,2010).

The challenge presented by the BLM's methane capture rule offers the oil and gas industry an opportunity to alter its approach by embracing the technological change necessary for reducing air pollution.

Case Study of San Juan Basin Gas Wells and the Methane Rule

The oil and gas industry in the U.S. is facing some serious challenges – some of which are self-inflicted wounds from over-production during an extended boom period. The industry is now in the bust phase of the boom and bust cycle. Commodity prices are down as are drilling rig counts. Shale gas production now provides competition for marginal natural gas wells in the Rocky Mountain states – as does associated natural gas produced from oil wells. Oil production from the Middle Eastern countries outcompete high cost producers in the US. And last but not the least is the oil and gas industry's serious debt problem[11].

With all of these other major economic challenges, the cost of the methane capture rule is not a primary economic factor for the determination of continued production versus well shut-in, and may very well improve most well financials. Because it will likely improve overall economic efficiency, as detailed in the RIA benefit cost analysis, an understanding of potential regional impacts can help inform local stakeholders. In order to understand the impact on the proposed LDAR requirements, we completed a case study for the San Juan Basin in New Mexico – a

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[11] Oil and gas company Energy XXI Ltd. recently filed for bankruptcy protection after spending $5 billion on acquisitions during the boom years before the current bust (Rizzo and Olson, Bloomberg News, 2016).

natural gas and oil producing region currently impacted by the low price environment of the bust phase of the boom and bust cycle. We first estimate the economic effect of methane rule compliance on marginal gas well operators by conducting a net present valuation (NPV) of compliance. With this filter we examine San Juan Basin marginal gas wells in northwest New Mexico to illustrate potential regional impacts on overall gas production and associated royalties.

We examine the methane rule compliance effect on the economics of San Juan Basin gas wells in the northwestern New Mexico counties of San Juan and Rio Arriba. San Juan and Rio Arriba counties are generally rural lands with small communities in northwest New Mexico and include substantial federal public lands and Indian reservations and trust lands. Oil and gas production and employment spiked in 2003 but are now decreasing (see Figure 1). In 2014, about ten percent of all jobs in San Juan County were associated with oil and gas development and about nine percent of the two counties employment combined were in oil and gas development (Census Bureau, County Business Patterns, as reported in Headwaters Economics' Economic Profile System).

Figure 1: Mining Sector Employment (Jobs) San Juan and Rio Arriba Counties, NM
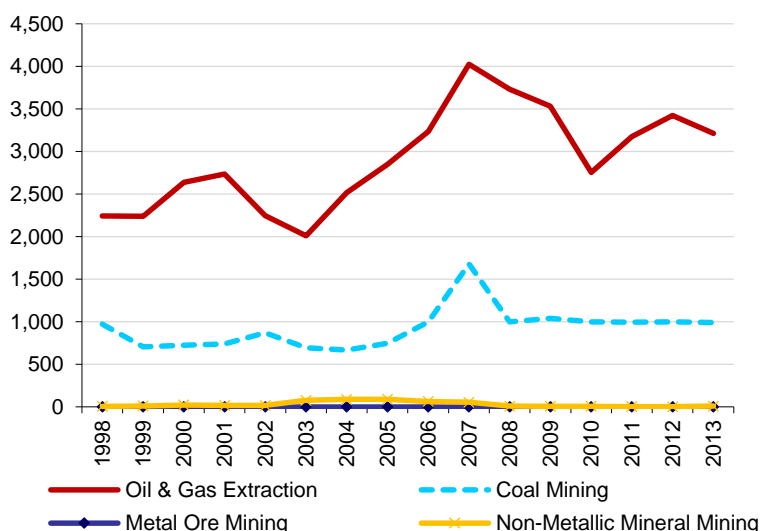
Source: U.S. Department of Commerce. 2015. Census Bureau, County Business Patterns, Washington, D.C., as reported in Headwaters Economics' Economic Profile System (headwaterseconomics.org/eps).

Due in part to competition from other regions, recent natural gas production in the San Juan Basin has been in decline. San Juan Basin natural gas production has fallen at an annualized trend-line rate of 4.7% since 2006, while U.S dry gas production has increased at a 4.2% annual-trend line rate over the same period (Natural Gas Intelligence 2016). [12]

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[12] The commodity downturn has proven to be too much for some producers. Samson Resources Corp., which operates in the San Juan along with a number of other basins, filed for Chapter 11 bankruptcy in September 2015 (Natural Gas Intelligence 2016).

After peaking at 14 in August 2011, the drilling rig count in the San Juan Basin stood at just 3 in early October 2015. 2 of those rigs were in Rio Arriba County, NM, with the third in San Juan County, NM. The flood of Marcellus gas supplies to market over the past few years, which dropped the commodity's price well below the crude oil value slump, led producers in the San Juan Basin away from the gassier part of the play and towards the oil-rich Mancos Shale portion located in the southern end of the basin. (Natural Gas Intelligence 2016).

Competition from more productive shale gas wells closer to the market is not expected to change in the short run. Volatile market price swings will continue to be a determining factor of profitability. These explanatory variables will have tremendous influence on well financials, with or without the methane capture rule.

The San Juan Basin is centered around the northwest New Mexico counties of San Juan and Rio Arriba. To better understand the scale of gas production and industry characteristics, we examined the economic characteristics of all federal, active gas wells in San Juan and Rio Arriba counties. The gas well data was pulled from the State of New Mexico's Oil Conservation Division.[13] In total, we examined 13,493 active federal gas wells in these two counties. We focused our analysis on a range of marginal wells that produce less than 90Mcf per day. These two counties have numerous marginal wells (8,718 or 65% of examined wells) that produce less than 90Mcf per day. Table 2 presents 2015 production data and marginal well characteristics for federal gas wells in San Juan and Rio Arriba counties of New Mexico.

Table 2: San Juan and Rio Arriba County Federal Marginal Gas Wells

Amount per production day	Number of Wells in 2015[*]	Percent of Total Wells	Total 2015 Production (MMcf)	Percent of Total Production
Wells with less than 15mcf	1,360	10%	3,682	0.85%
Wells with less than 30mcf	3,082	23%	16,608	3.85%
Wells with less than 60mcf	6,311	47%	66,032	15.29%
Wells with less than 90mcf	8,718	65%	128,634	29.79%
Total[**]	**13,493**	**100%**	**431,776**	**100%**

*Active, Federal wells only with greater than10 days of production in both 2014 and 2015, and greater than zero amount produced in both 2014 and 2015.
** Totals include all marginal and non-marginal wells. Marginal well categories are cumulative and do not add up to the total.
Source: New Mexico Oil Conservation Division: http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx.

Effect of Proposed LDAR Requirements on San Juan Basin Marginal Gas Wells

The regulatory analysis, the literature, and industry examples (e.g., Encana 2014) all indicate that the methane rule will largely result in increased efficiencies and reduced pollution and waste for oil and gas operators. With little information on how marginal well financials may be affected by the proposed requirements nationally, we examine the economic effect on San Juan

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[13] Available at: http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx.

marginal gas wells of the proposed LDAR requirements in order to provide a regional case study. The primary economic components to consider for the distributional impacts of the rule in the San Juan Basin include the existing amount of leaked and wasted methane, anticipated capture rate of leaked methane, the costs of compliance, and the estimated revenue of newly captured gas.

Methane Leakage

Addressing air pollution and operational inefficiencies from oil and gas development are important nationally, but are of particular importance in the San Juan Basin. The San Juan Basin has one of the highest rates of methane emissions and natural gas waste in the country. Recent analysis from the Clean Air Task Force (2015) illustrates that natural gas production from the San Juan Basin accounts for four percent of all U.S. gas production, yet accounts for almost 17 percent of all reported U.S. methane loss. Other Western gas producing basins have been estimated to have methane leakage rates of 6%-12% (Uinta Basin, Karion et al. 2013) and 2%-8% (Denver, Petron et al. 2012, 2014).[14] A recent review of methane emission studies found emissions to be vastly underestimated (Brandt et al. 2014). Brandt et al. (2014) indicated average U.S. methane emissions from natural gas production of 5.4%.

To account for a range of methane leakage estimates in the San Juan Basin, we consider a range of methane leakage rates from 3% -- 12% of total production. For the NPV analysis and the net state royalty effects, we assume an average leakage rate of 6% for the San Juan Basin over time. A 6% methane leakage rate is based on the national estimates calculated by Brandt et al. (5.4%), and increased slightly to account for the San Juan Basin's higher than average leakage rates[15]. Based on the BLM's RIA, we model LDAR compliance costs and capture rate under assumed semi-annual monitoring. The LDAR capture rate for semi-annual monitoring is 60% of total leakage.

LDAR Compliance Costs

We use facility compliance cost estimates from the RIA (Table 31) to project additional annualized equipment and monitoring costs under the new rulemaking. Annualized compliance cost estimates were $1,869 per facility when using a three percent discount rate, $1,879 per facility when using a seven percent discount rate. We believe the compliance costs per facility are likely to vary based on the size and production amount of each well, but we were unable to determine a rate of change in compliance costs for the differently sized marginal wells. We believe the average compliance cost results in overestimated compliance costs for the smallest wells (e.g., less than 15Mcf/day), indicating our NPV analysis is likely conservative.

New Revenue from LDAR Compliance

New revenue is generated as increased production of natural gas occurs from compliance with the methane rule. Market prices dictate the amount of new revenue into the future. For the

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[14] The estimated leakage rates include fugitive methane emissions from leaks from gas wells and venting from oil wells.
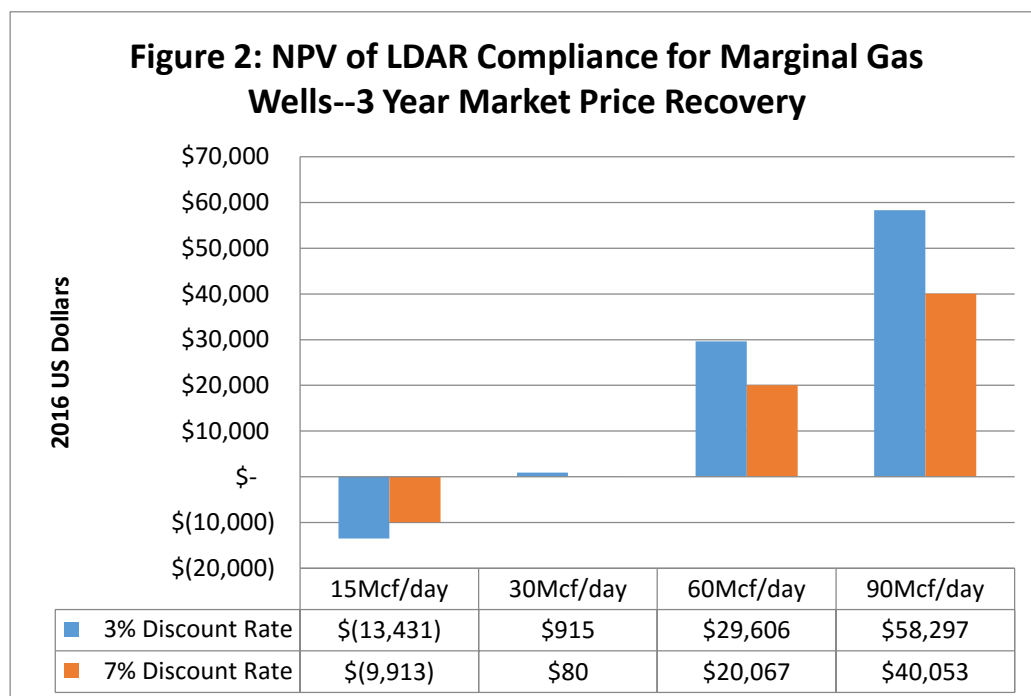
[15] For this analysis we assumed a 6 percent leakage rate for leaks from gas wells. This is a reasonable assumption given the preponderance of natural gas wells in the San Juan Basin.

NPV analysis, we model two gas market scenarios: a three-year and a four-year market price recovery back to recent San Juan Basin wellhead long term averages.   From the Energy Information Administration (EIA),[16] average natural gas wellhead prices in New Mexico were $5.21 from 2000-2010, which includes a number of years above and below this average. While current prices are low, national forecasts from the EIA (2016) indicate natural gas prices will increase in the future: nearly doubling in the next 18 months.

Under a three-year recovery to average wellhead prices, we assume a market price of $2/Mcf for the first year of the methane rule implementation, $3.50/Mcf for the second year, and all remaining years at $5.21/Mcf to cover ups and downs in future gas prices. Under a four-year market price recovery, we model a natural gas marketplace that extends the current low prices in the first year ($2/Mcf) of compliance, then increases the natural gas market price to $3/Mcf in year two, $4/Mcf in year three, and uses the recent long term average market price of $5.21/Mcf for the remaining years.

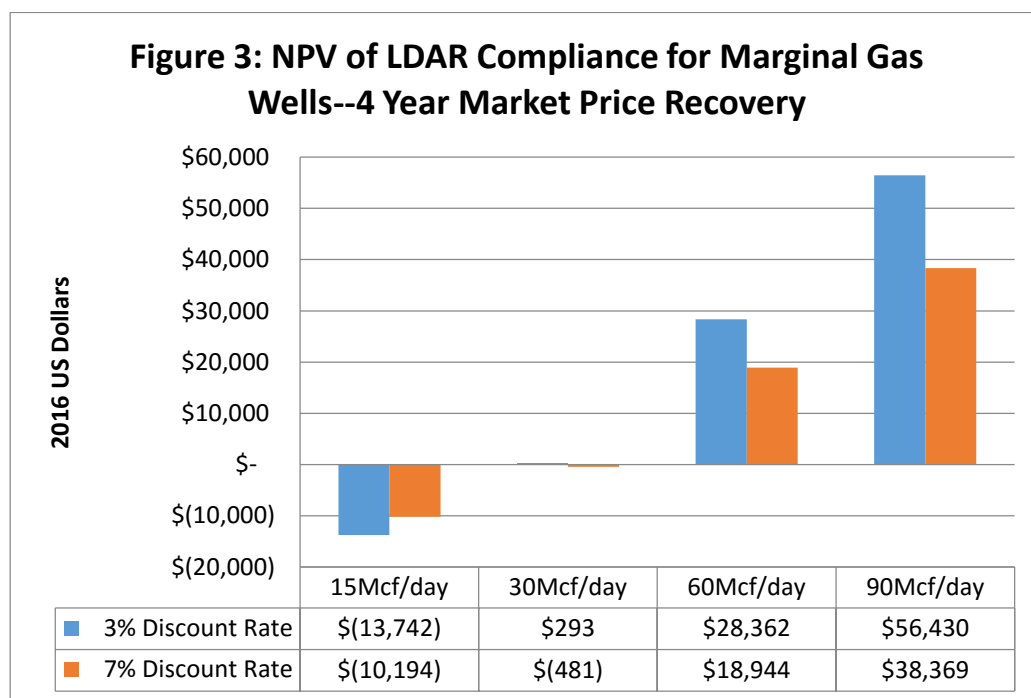### NPV Analysis of Marginal Wells and LDAR Compliance

Using an assumed average leakage rate of 6% and the market prices and compliance costs detailed above, we estimated the net present value (NPV) of methane rule compliance for four categories of marginal gas wells: <15Mcf/day, <30Mcf/day, <60Mcf/day, and <90Mcf/day. Modeled attributes include a 20-year time horizon with wells producing every day of the year. We assume a 60% capture and production rate of detected leaked methane as recommended by the RIA for semi-annual surveys and estimate values at two discount rates (3% and 7%). NPV results are presented in Figures 2 and 3 below.

Figure 2: NPV of LDAR Compliance for Marginal Gas Wells--3 Year Market Price Recovery

2016 US Dollars

	15Mcf/day	30Mcf/day	60Mcf/day	90Mcf/day
3% Discount Rate	$(13,431)	$915	$29,606	$58,297
7% Discount Rate	$(9,913)	$80	$20,067	$40,053

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[16] Available at: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_snm_a.htm

Under the 3-Year Market Price Recovery Scenario (Figure 2), estimates indicate that for the majority of marginal gas wells, compliance with the methane rule will not only be a source of emission reductions, but one of economic efficiency as well. Like the rest of the gas industry, most marginal wells will likely generate increased profits from the methane rule. Our analysis indicates that only marginal gas wells that produce less than 15Mcf/day result in a negative NPV when modeling methane rule compliance. But the net costs (compliance cost minus new revenue) for these producers is quite small, about $1,000 annually for the first couple years. This suggests a small increase in overall costs, and a minimal increase in net costs for just the smallest wells.

With a slower market recovery of four years (Figure 3), marginal gas wells that produce less than 15Mcf/day still result in a negative NPV when modeling methane rule compliance. But, under the 4-Year Market Recovery Scenario, marginal wells less than 30Mcf/day are at an NPV breakeven point where the NPV of methane compliance is positive for a 3% discount rate, but negative for a 7% discount rate.

Figure 3: NPV of LDAR Compliance for Marginal Gas Wells--4 Year Market Price Recovery

2016 US Dollars

	15Mcf/day	30Mcf/day	60Mcf/day	90Mcf/day
3% Discount Rate	$(13,742)	$293	$28,362	$56,430
7% Discount Rate	$(10,194)	$(481)	$18,944	$38,369

A recent U.S. Energy Information Administration report[17] on oil and gas lease equipment and operating costs estimated average annual operating and equipment costs for Rocky Mountain gas wells at average depth of approximately $64,000 for marginal gas wells producing 50Mcf per day. With the annualized estimate for LDAR compliance for facilities from the RIA ($1,867), overall compliance costs represent less than three percent of annual costs for average marginal

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[17] Available at:
http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

wells. After factoring in revenue from captured leaked methane, LDAR compliance costs will drop close to 1 percent of annual costs. Our estimate is similar to results from the RIA indicating that some of the smallest producers would likely see a very small decrease in annual profit margin (RIA p. 15).

The presented NPV estimates should be considered conservative for a couple of reasons. First, evidence from the field indicates that methane compliance costs will decrease over time and it is likely that compliance costs for the smallest operators will be quite a bit lower than the costs for larger producing wells. Additionally, leakage rates will likely start much higher than the assumed 6% average and will decrease over time as leak detection and repair are implemented. Modeling higher leakage rates in the early years of the NPV analysis indicates that actual NPVs of the compliance rule will likely be more positive than illustrated here.

Estimated Effect of the Proposed LDAR Rule on San Juan Basin Royalties

We estimated three scenarios of the economic effect of the methane rule on San Juan Basin royalties to the state of New Mexico. Federal royalty rates of 12.5% were used; with about half of these royalty rates being returned to the states (state royalty rate approximately equals 6.25%). We examined the net amount of annual state royalties based on three scenarios. The first scenario models a continuation of all active federal gas wells in San Juan and Rio Arriba counties, with no loss of gas wells due to methane rule compliance and with estimated amounts of new methane captured. In Scenario 2, we estimate the net effect on royalties if all of the smallest marginal operators (15Mcf/day and less) were forced to shut wells in due to methane rule compliance. Royalty scenario 3 estimates the net effect of the shut-in of half of all marginal wells producing less than 30/Mcf per day.

For the net marginal royalty effect, we use the following parameters:

(New royalties collected under methane rule compliance) – (lost royalties from lost production) = net marginal royalty effect.

Where new annual royalties = [*total production from our dataset (432Bcf) – assumed lost production*] * [*assumed leakage rate * capture rate*] * *$market price * state royalty percentage (0.0625)*.

And where lost royalties = *[assumed lost production * $market price * state royalty percentage (0.0625)]*.

Total gas production from active, federal gas wells in these two counties was about 432 Bcf in 2015 (see Table 2). Under Scenario 1, we model the increase in royalties under a 6% methane leakage rate for the San Juan basin and across three market prices for captured gas ($2/Mcf, $4/Mcf, $6/Mcf). A capture rate of leaked methane of 60% was applied to the leakage rates, leading to the capture and sale of some 15.5 Bcf of gas. Results are presented in Figure 4. Under this Scenario, the methane rule would have a positive effect on state royalties under all examined market prices.

Figure 4: Annual State Royalty Scenario 1--LDAR Compliance and No Loss of Gas Wells
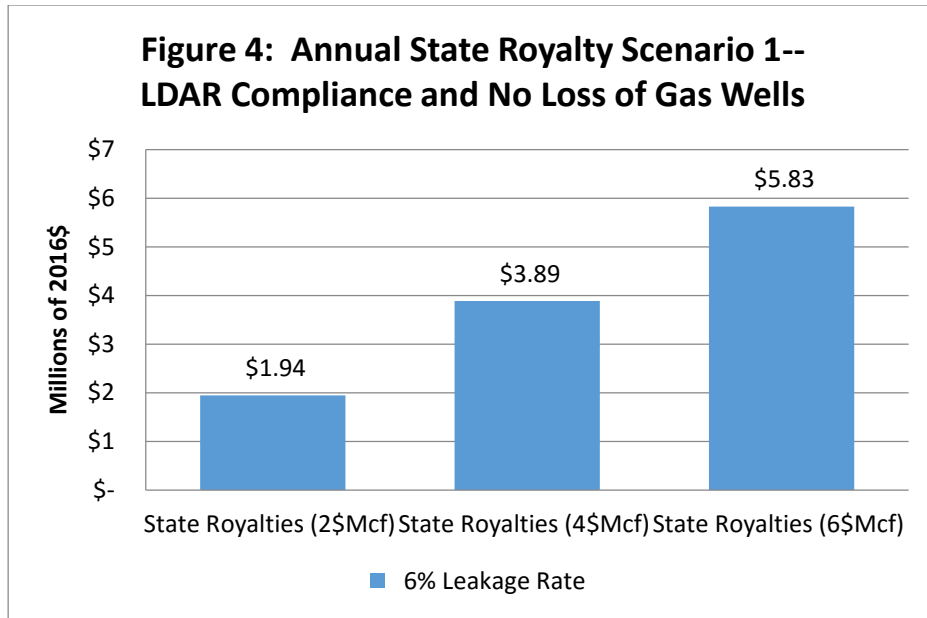

In the second scenario, we estimate the net royalty effect of shutting in all marginal wells producing less than 15Mcf per day. From our San Juan and Rio Arriba gas well dataset, approximately 1,360 San Juan gas wells produced less than 15Mcf per day, or 10 percent of total gas wells examined (n=13,493). The less than 15Mcf marginal gas wells only provide less than one percent (.85%) of the total federal gas production in the two counties, leading to minimal changes to overall royalty rates. Scenario 2 compares the lost royalties from the modeled lost marginal well production (3.68 Bcf) to the royalties gained from new methane capture by non-marginal and other marginal wells continuing production and complying with the methane rule. Again, we estimate new royalties based on three sets of market prices for captured methane. A capture rate of leaked methane of 60% was applied to the leakage rates. Results are presented in Figure 5. This scenario also indicates a positive effect on state royalties at all examined market prices, even when losing the most marginal wells from production.

Figure 5: Annual State Royalty Scenario 2-- LDAR Compliance and Loss of all <15Mcf/day Wells
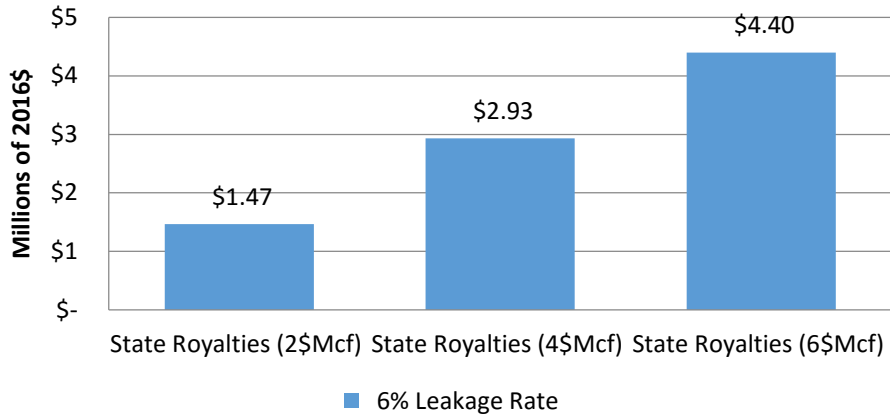
In the third net royalty scenario (Figure 6), we examine the net marginal effect of the San Juan Basin producers complying with the methane rule and the rule causing half of all marginal wells producing less than 30Mcf/day to be shut in. In this scenario, as with the previous two, new production of gas from remaining producers outpaces the lost production from losing 50% of all 30Mcf/day producers (a loss of 8.3Bcf annually) and results in a net increase in state royalties. At an overall leakage rate of 6%, net royalties to the state will decrease once all less than 30Mcf/day wells are shut-in, or a loss of 23% of all active federal wells in the San Juan Basin.

Figure 6: Annual State Royalty Scenario 3-- LDAR Compliance and Loss of 50% of <30Mcf/day Wells
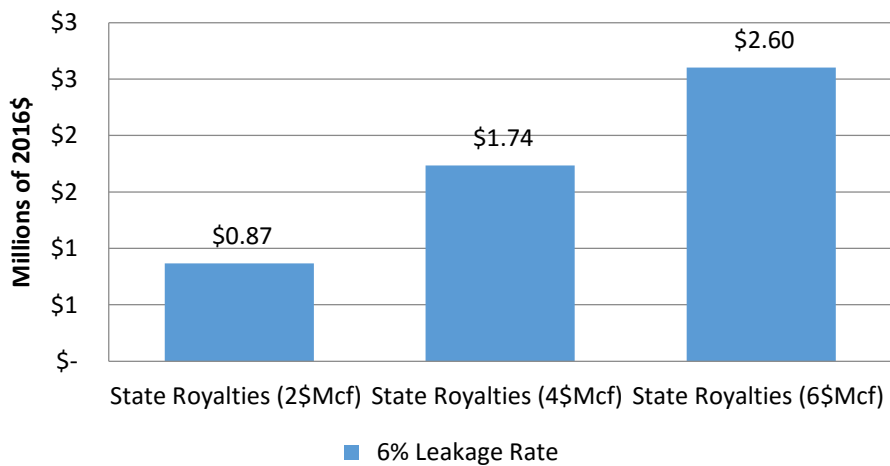
Our analysis indicates that complying with the methane rule would have a small, positive effect on production and royalties in the San Juan Basin. This is consistent with the literature and with the BLM's findings in the RIA. In terms of whether or not methane rule compliance will cause some marginal wells to be shut-in, we see that only the smallest marginal wells have a negative NPV for compliance. However, a minimal decrease in profit margin will not be the sole reason for a shut-in decision. Many other variables have much greater economic effect on the financial analysis and operating decisions of wells. As such, we view the methane rule's overall effect on the number of wells to be negligible in the San Juan Basin.

Summary and Conclusion

The BLM's methane capture rule has been illustrated to be an improvement in economic efficiency at both the national and regional levels, while also representing substantial decreases in emissions and pollution. The BLM's regulatory impact analysis indicates that societal benefits of the methane rule will exceed costs by as much as $200 million annually. An examination of the environmental regulatory compliance literature also indicates that the methane capture rule can provide a win-win scenario for the environment and for industry's bottom line.

By aggressively supporting and adopting the requirements from the methane capture rules, industry will help do its part to protect the environment. As drilling has moved closer to populated areas and the damage becomes more visible, industry's "social license to operate" has come into question (Morton and Kerkvliet 2014). The concept of social license to operate comes from increasing consumer awareness and stakeholder groups that exert influence beyond the traditional governmental roles (Berkhout 2014). Neglecting social concerns can have drastic negative impacts on performance (Ford et al. 2014). Beyond a genuine desire 'to do the right thing', by embracing the methane capture rule the oil and gas industry will retain its social license to operate.

Due to the outside economic challenges being faced by the oil and gas industry, the cost of the methane rule is not a primary economic factor for the determination of continued production versus well shut-in, and may very well improve most well financials. Many other economic variables have a much greater economic effect on the financial analysis and operating decisions of wells than the BLM's methane capture rule. Compliance costs for leak detection and repair (LDAR) represent less than 3% of annual operating costs and in almost all cases will result in positive net revenues from capturing previously wasted methane. Based on our regional analysis of San Juan Basin marginal gas wells, only the smallest, or most marginal, of federal gas wells will have a negative NPV of complying with the LDAR requirement. Marginal wells producing less than 15Mcf per day exhibited negative NPV for the LDAR rule. But, it is important to note that based on an examination of approximately 13,500 San Juan Basin federal gas wells, marginal wells producing less than 15Mcf per day contributed less than one percent of the overall gas production. Thus, any possible economic effects of the LDAR rule on the most marginal gas wells in the San Juan Basin are unlikely to have a noticeable effect on the overall regional gas industry.

An examination of the LDAR rule effect on federal gas royalties demonstrated that both federal and state residents stand to benefit from the rule. We investigated three possible royalty scenarios in the San Juan Basin based on the hypothetical shut-in of all marginal wells producing less than 15Mcf per day, the shut-in of half of all marginal wells producing less than 30Mcf per day, and a scenario where no marginal wells are shut-in. Focusing on royalties to the state of New Mexico, we found all scenarios yielded a positive net royalty effect with new

royalties ranging from approximately $1 million -- $6 million annually depending on natural gas market prices. With increases in production, increases in annual royalties, and decreased emissions and pollution, the methane capture rule will result in a net positive economic effect nationally and locally.

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