Attachment B

Analysis of the Benefit-Cost Analysis in the Regulatory Impact Analysis of 2018 Proposed Revisions of 43 CFR Subpart 3197

ERM Analysis in Support of API Comments April 23, 2018

BLM Proposed Rule "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements"

83 Fed. Reg. 7924 (Feb. 22, 2018) (RIN 1004-AE53)

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Executive Summary

In November 2016, the Bureau of Land Management adopted a rule that, among other things, created a new regulation: 43 CFR Chapter II, Subpart 3179, titled "Waste Prevention, Production Subject to Royalties, and Resource Conservation", which regulates the methane emissions for BLM onshore oil and gas leases (2016 Rule)[1]. Key components of Subpart 3179 include: semi-annual leak detection and repair programs (LDAR); a capture target program to reduce flaring at oil wells; and the replacement of pneumatic controllers and pumps, storage vessels, and liquids unloading. At the same time, BLM issued a Regulatory Impact Analysis (2016 RIA) that includes estimates of the economic impact of these key components. In 2018, BLM proposed a modified rule (2018 Proposed Rule) that effectively rescinds the portions of the 2016 Rule described above and issued a new RIA (2018 RIA).

ERM reviewed the assumptions, calculations and analysis used in the 2018 RIA on behalf of API. This analysis summarizes the savings (i.e., the avoided net costs) to the regulated industry that would result from rescinding the key provisions of the rule as well as the change in social benefits from changes in emissions. The industry savings and social benefits are measured from 2019–2028, the ten-year period covered by the 2018 RIA, using a seven and a three percent discount rate. Results for both seven and three percent discount rates are included in the summary tables, but only results for seven percent are described in the text.

In summary, the analysis shows that the 2018 proposed rule will provide substantial savings to the regulated industry and a small foregone social value from emission increases (Table 1). The proposed rule will provide annualized savings or avoided net costs of approximately $192.4 million and a reduction in social benefits of $2.9 million (Table 1). These API estimates are in contrast to the 2018 RIA estimates of annualized savings of $119.6 million, and reduction in social benefits of $9.4 million. In present value terms, the total avoided costs are $1.3 billion based on API estimates compared to $774 million based on the 2018 RIA (Table 2).

In addition, this analysis provides estimates of the additional oil production from marginal wells that will likely result from rescinding the above rule provisions. Eliminating these rule components will increase oil and gas production on BLM-administered leases by at least 0.3 million barrel of oil equivalent (MM BOE) on an annualized basis over the next 10 years. The additional production is valued at $21 million and supports approximately $9 million in earnings and 159 jobs nationally on an annualized basis.

The basis for the API estimates as well as the description of the causes of the differences between the 2018 RIA and the API estimates are described in the following sections of this report.

[1] 81 FR 6616 (February 8, 2016).

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Table 1: Estimated Annualized Impact of 2018 Proposed Rule, 2019-2028 ($millions 2016)

	Seven Percent Discount Rate		Three Percent Discount Rate	
	API Estimates	Estimates from 2018 RIA	API Estimates	Estimates from 2018 RIA
LDAR (net of gas sales)	$92.8	$61.8	$97.1	$63.4
Flaring Capture Target(net of gas sales)*	$72.7	$37.9	$100.5	$62.3
Pneumatic controllers and pumps, storage vessels, liquids unloading (net of gas sales)**	$12.9	$5.9	$10.7	$3.4
Administrative Burden ***	$14.0	$14.0	$14.0	$14.0
Total Annualized Savings/Avoided Costs	$192.4	$119.6	$222.4	$129.1
Value of Foregone Emission Reductions	$(2.9)	$(9.4)	$(8.8)	$(30.4)
Net Benefits	$189.1	$110.2	$213.8	$112.8

*API: mean value from Monte Carlo model. 2018 RIA: average of low and high cost estimates.

** API evaluated gas sales only. Compliance cost is from 2018 RIA.

*** API did not evaluate costs. Cost is from 2018 RIA.

Table 2: Estimated Present Value of 2018 Proposed Rule, 2019-2028 ($millions 2016)

	Seven Percent Discount Rate		Three Percent Discount Rate	
	API Estimates	Estimates from 2018 RIA	API Estimates	Estimates from 2018 RIA
LDAR(net of gas sales)	$652	$434	$97.1	$445
Flaring Capture Target(net of gas sales)*	$511	$267	$706	$438
Pneumatic controllers and pumps, storage vessels, liquids unloading (net of gas sales)**	$91	$41	$75	$24
Administrative Burden ***	$98	$98	$98	$98
Total Savings/Avoided Costs	$1,351	$840	$1,562	$1,005
Value of Foregone Emission Reductions	$(20)	$(66)	$(62)	$(231)
Net Benefits	$1,331	$774	$1,500	$792

*API: mean value from Monte Carlo model. 2018 RIA: average of low and high cost estimates.

** API evaluated gas sales only. Compliance cost is from 2018 RIA.

*** API did not evaluate costs. Cost if from 2018 RIA.

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1. LDAR Inspection Program

Eliminating the leak detection and repair (LDAR) inspection program requirements will save the regulated industry an estimated $92.8 million annually compared to the final rule (Table 3). This amount is $31 million more than the BLM estimate of the net cost to industry of implementing the 2016 Rule. The foregone value of methane emission reductions are approximately $1.6 million.

Table 3: Annualized LDAR Compliance Costs, 2019-2028.

	Seven Percent Discount Rate		Three Percent Discount Rate	
	API Estimates	**Estimates from 2018 RIA**	**API Estimates**	**Estimates from 2018 RIA**
Number of Wells*	43,964	36,700	43,964	36,700
LDAR Cost Per Well	$2,607	$2,136	$2,607	$2,136
LDAR Compliance Costs ($millions)	$99.5	$78.4	$103.0	$80.7
Gas Sales ($millions)	$(6.7)	$(16.6)	$(7.1)	$(17.3)
Net Avoided Compliance Costs/Cost Savings	$92.8	$61.8	$97.1	$63.4
Value of Foregone Emission Reductions	$(1.6)	$(4.8)	$(5.2)	$(15.3)
Net Benefits	$91.2	$57.1	$91.9	$48.1

*API: average annual. 2018 RIA: number of wells is constant over time.

The API compliance cost estimates differ from the 2018 RIA estimates for the following reasons:

- The 2018 RIA underestimates the number of wells that would be covered by the rule during 2019and overestimates the number covered in 2028.
- The 2018 RIA underestimates the compliance costs of implementing LDAR. The 2018 RIA overestimates the frequency of leaks (leak incidence) and the amount of gas captured from leaking components, and thus the captured gas not released.

Underestimate of Regulated Wells

The estimated number of wells provided in Table 3 is an annual average of the wells that are subject to the LDAR requirements. At the request of API, ESS conducted a detailed analysis of the number of wells that would be covered by the LDAR requirements of 2016 Rule (ESS 2018). Their analysis shows that when the 2016 Rule became effective it would affect 63,152 wells but by the end of the ten year period only 24,776 would remain active. This results in an average annual number of wells of 43,964. This estimate excludes wellhead only wells that are exempt from the 2016 Rule requirements and wells that would already be affected by an LDAR program either through NSPS OOOOa or through a state regulation. Additionally, the ESS analysis accounts for the typical rate of well closures. In contrast, the 2018 RIA includes wellhead only wells and assumes a constant number of wells for the entire ten-year period.

Underestimate of Compliance Costs

The 2018 RIA also underestimates compliance costs per well and API has developed an alternate estimate of the semi-annual LDAR costs based on outsourcing the OGI monitoring to a third party contractor, similar to the assumptions used by BLM and EPA.[2] These costs were derived from the EPA methodology for the NSPS OOOOa rulemaking, but were adjusted for the following key issues:

- Adjusting the costs for a wellsite with multiple wells (i.e., 2 wells per wellsite on average), as opposed to a wellsite with a single well;
- Including administrative costs and elements that were missing or underestimated in EPA's initial estimate (e.g., resurvey costs after repair, travel time to survey and repair leaks, etc.).

Overestimate of Gas Sale Volume

The volume of natural gas recovered (and sold) per well by the LDAR program is overestimated in the 2018 RIA. The two reasons for the overestimate are:

- The 2018 RIA overestimates the initial leak incidence rate prior to LDAR program implementation.
- The 2018 RIA uses inflated emissions factors and well site component counts.

API data indicates that actual initial leak incidence rate for well sites is approximately 0.4 percent, which is consistent with other recent publications (Kuo 2012, Kuo 2015). The 2018 RIA assumed a higher initial leak rate, which translates to a higher number of leaking components prior to implementation of an LDAR program. Additionally, the BLM overstated the component counts per well site, and hence overstated the methane emission reductions and gas savings. To correct for this overstatement, this analysis uses the same approach developed by by ESS and scales the 2018 RIA LDAR gas volume and methane emissions by (0.4/1.18).

[2] Note that the API costs for the outsourced OGI monitoring program were conservatively based on the same references as EPA and BLM used in developing their costs. (API, 2016)

The overestimate of the gas capture volume also results in an overestimate of the methane emissions without the 2016 Rule being in place. As a result, the social value of methane reductions is overstated in the 2016 Rule, which also means the foregone social benefits of rescinding the LDAR requirements in the 2018 Proposed Rule are also overestimated. (See Section 4 for a summary of the foregone social benefits.)

2. Flaring and Capture Requirements

Implementing Alternative 2 would cost the regulated industry an average of $84 million per year (Table 4), which has an average cost $38 million higher than the 2018 RIA.

Table 4: Annualized Flaring Capture Compliance Costs

	API			2018 RIA		
	Low (5th %tile)	High (95th %tile)	Average	Low	High	Average
Seven Percent Discount Rate						
Compliance Costs ($millions)	$(88)	$(65)	$(78)	$(79)	$(118)	$(98)
Gas Sales ($millions)	$5	$11	$8	$60	$60	$60
Net Avoided Costs ($millions)	$(84)	$(59)	$(73)	$(18)	$(58)	$(38)
Three Percent Discount Rate						
Compliance Costs ($millions)	$(121)	$(89)	$(103)	$(103)	$(154)	$(128)
Gas Sales ($millions)	$4	$8	$6	$66	$66	$66
Net Avoided Costs ($millions)	$(115)	$(82)	$(100)	$(36)	$(88)	$(62)

Analysis Basis and Assumptions

Alternative 2 in the 2018 RIA includes updated cost estimates of eliminating the flaring and capture requirements of the 2016 Rule. Although BLM does not propose to impose the flaring and capture requirements, in the analysis of alternatives section of the 2018 RIA, under Alternative 2, these requirements would be retained. The avoided costs from implementing the 2018 Proposed Rule and eliminating the flaring and gas capture requirement is the estimated cost of implementing Alternative 2.

The 2018 RIA states only minor changes were made in updating the flaring and capture requirement costs between the 2016 RIA and the 2018 RIA as follows:

- The implementation period is 2019 to 2028,

- The future price predictions for the natural gas and oil were updated as of 2017, and
- All dollars are in 2016 dollars.[3]

There is no indication in the 2018 RIA that any other assumptions were changed. Therefore, this analysis assumes that the amount of flaring, excess flaring and the number of wells and leases affected by the 2016 Rule are all based on the FY 2015 Office of Natural Resources Revenue (ONRR) information that was used in the 2016 RIA. Furthermore, this analysis assumes operator response to the 2016 Rule with respect to either deferring production or relying on CNG trucking, along with the growth of capacity, are unchanged.[4]

This analysis uses a Monte Carlo model to better capture the uncertainty surrounding the key parameters and cost assumptions specific to the flaring requirements. The set of assumptions used within the model are different than those used in the 2018 RIA and described below in more detail. In contrast, the 2018 RIA uses a set of fixed assumptions, and only considers the potential uncertainty about CNG trucking costs.

Uncertainty is important to evaluate because uncertainty is a form of risk and is a direct cost to the regulated industry. The Monte Carlo model uses a range of values for each parameter that is uncertain (Table 5). For most parameters, because information to fully characterize the range is not available, we use a uniform distribution. A value from the range for each parameter is randomly selected and the net cost is calculated. This process is repeated 10,000 times, providing 10,000 net cost estimates, which are used to calculate the average net cost and the range. The 5th percentile value (i.e., the 500th lowest value) is used as the Low estimate and the 95th percentile value (i.e. the 9,500th highest value) is used as the High estimate. Table 5 describes the basis for the specifications for each parameter.

Table 5: Parameters for the Monte Carlo Model

Parameter	Average	Low	High	Type of Distribution
Capacity Growth	2 percentage points per year	0 percentage points per year	4 percentage points per year	Uniform
Percent excess flaring deferred	Varies based on capacity growth	20 percent	1 – capacity growth	Uniform
Percent excess gas captured by CNG	1 – (capacity growth+ percent deferred)			Uniform
Average annual decline in active wells/production	12.7 percent	90% of average	110% of average	Uniform

[3]Although the 2016 RIA covers a ten year period, 2017 to 2026, it is assumed that the flaring and capture requirements are not effective until 2018. Therefore, the 2016 RIA effectively covers a nine year period.

[4] Since the 2016 RIA only shows the operator response for nine years, API assumes the operator response in the tenth year is the same as in the ninth year.

Average annual oil/gas price growth rate*	3 percent	Approximately 0	Approximately 4.5 percent	Normal
Annual volatility in oil/gas price (deviation from long term trend)*	0 percent	Approximately -8 percent	Approximately + 4 percent	Normal

*Low and high values are described as 2 times the standard deviation

Capacity Growth

In the 2018 RIA, the estimated amount of gas flaring was assumed to be addressed by either increase in pipeline capacity, deferred production, or CNG trucking. The percentage of excess flaring assigned to each category varies by year. Pipeline capacity increase begins at two percent and increases by two percent per year in the 2018 RIA. The two percent increase is based on a statistical model described in the 2016 RIA. The detailed model results are not reported, which means the uncertainty around the annual percentage increase is unknown. For the purposes of this analysis, the parameter was assumed to be statistically significant at the 95 percent level, which implies a range of +/- two percentage points.

Percent Deferred

The percent of production deferred in the 2018 RIA ranges from five to twenty percent. The API analysis submitted in response the 2016 Rule shows that the only economically viable response to flaring limits is deferred production, for both connected and unconnected leases. The 2016 analysis also points out that connected leases have already invested in gas infrastructure sufficient to capture gas where it is economically viable to do so. Most flaring on connected leases is from operational upsets (e.g., compressor going down) or temporary lack of pipeline and/or gas processing capacity. It is common to have intermittent flaring on an hourly or daily basis due to operational conditions. Therefore, additional investment to install technology to capture flared gas during upset conditions is unlikely to occur; otherwise, it would have already been implemented. However, if the cost of deferment is high, some operators may choose to use CNG trucking as a lower-cost alternative, especially unconnected leases or those close to gathering stations.

CNG Trucking

Unfortunately, there is insufficient data for estimating the breakdown between deferred production and CNG trucking. Consistent with our initial comments from 2016, API assumes for a high value that all excess flaring not captured by increases in pipeline capacity is deferred.[5]

For a low value, we use information from the FY 2015 ONRR lease data that BLM made publicly available. Carbon Limits 2015 (CL) noted that CNG trucking is less likely to be

[5] The 2018 RIA assumes that oil production will be deferred by 10 years. API believes this value is too high, especially considering that roughly 50 percent of the wells would cease production over that time. Therefore, API assumes production would be deferred for 5 years.

economically viable for wells producing less than 200 thousand cubic feet of natural gas per day or a geographic area where there are less than 5 wells. CL also notes that "*scale is limited by demand (e.g., capacity of trucks, distance, number of trips that need to be made)*" and that it is "*difficult to put product in the market. Finding customers is not straightforward; it may require mid-term contract. Conditions are not clear at this point.*" (CL 2015, p. 33). From the ONRR data, API estimates that approximately 18 percent of the leases included in the BLM database from the eight states produce at least 200 thousand cubic feet per day.[6]

For the cost of CNG trucking, the high cost estimates for operating costs from the 2016 RIA are largely consistent with the on-site capture cost estimates API developed. However, the 2016 RIA capital costs are significantly underestimated. The basis for the 2016 RIA capital cost estimate is CL 2015. The CL cost estimate does not include dehydration, and a footnote mentions that molecular sieve dehydration is required to reduce the moisture level in order to avoid hydrate formation when the gas is compressed between 1900 and 3600 pounds per square inch gauge. This process is not as straightforward as putting in a glycol dehydration unit. Mole sieve dehydration units typically operate with two vessels. The natural gas being dehydrated effectively alternates flowing between the two vessels - with gas being dehydrated in one vessel while the second vessel undergoes a regeneration cycle. In addition, the 2016 RIA capital cost does not include any gas sweetening if hydrogen sulfide or carbon dioxide is present at levels that require removal, which would be required in some, but not all areas. Based on these factors, the capital costs are assumed to be 25 to 50 percent higher than the CL capital costs. Since capital costs are approximately 50 percent of total costs, the total costs are approximately 12.5 to 25 percent higher than the 2018 RIA costs.

Cost of Deferment

The cost of deferment in any year is the difference between the current price and the estimated price to be received after the deferment period.[7] However, the future price of both the deferred oil and any associated gas is uncertain and the Monte Carlo model accounts for that uncertainty. First, it considers the uncertainty of the 10 year growth rate in oil prices. The 2016 RIA assumes the average annual growth rate will be 3.1 percent. The Interstate Oil and Gas Compact Commission data shows that that the standard deviation is approximately 50 percent of the historical 10 year average annual growth rate, which is the percentage applied in this analysis. That data also shows the annual deviation in price is approximately 9 percent. In other words, in any given year the price is likely to be +/- 9 percent off of the long-term trend. This annual volatility was also included into the Monte Carlo model analysis.

[6] As the database BLM made available did not include the number of wells associated with each lease, API computed the statewide average number of wells per lease on federal land reported in the BLM Oil and Gas Statistics, Tables 5 and 9 (https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics).
[7] Deferment will impose additional costs on the operators, because of capital costs, contracts for delivering oil, and declining productivity, etc. To reflect these costs, API uses ten percent of the current price. The 2018 RIA adopted this approach as well.

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The ESS analysis shows that the number of active wells will decline over the ten year period by an average rate of 12.7 percent per year for the states with flaring. To account for potential uncertainty with this estimate the Monte Carlo model uses a range of the 90% to 110% of the average.

3. Economic Costs of Compliance by Marginal Wells

One major concern is that the 2016 Rule will disproportionately affect marginal and low-producing wells and small operators. Compliance costs are substantially higher per unit of output for marginal and low-producing wells. Higher production costs could lead operators to prematurely abandon or temporarily shut-in marginal wells, both effectively resulting in the same production impact.[8] While the 2016 Rule would provide operators of marginal wells partial exemptions from LDAR requirements, the cost of furnishing required information and the potential disclosure of business confidential information will deter operators from seeking them.

Although the 2018 RIA acknowledges marginal wells could not support compliance costs and that the administrative costs would be burdensome on small operators, BLM does not attempt to quantify the potential economic impact of the 2016 Rule. However, it is important for understanding the disproportionate cost impact on small operators of BLM-administered leases that, as the 2018 RIA acknowledges, could be significant within the context of their contribution to the national economy.

Estimated Economic Impact of Additional Production from Marginal Wells

Eliminating the LDAR, pneumatic devices and storage tanks compliance costs will reduce production costs of marginal oil and gas wells (as defined by the Interstate Oil and Gas Compact Commission) associated with BLM-administered leases by an average of $6.40 per BOE in 2019. However, the cost impact is substantially higher for the lowest-producing marginal wells as listed in Table 6.

Table 6: Compliance Cost of the 2016 Waste Prevention Rule on Marginal Wells in the Top-8 BLM Oil & Gas States

Daily Production Rate	Marginal Wells on BLM Land (#)	Average Annual Production (BOE/Well)	Compliance Cost per Unit ($/BOE)
<1 BOE	10,766	58	$44.13
1-2 BOE	6,596	193	$13.21
2-4 BOE	10,067	347	$7.34
4-10 BOE	18,493	696	$3.66
≤ 10 BOE	45,922	398	$6.40

Sources: **EIA's U.S. Oil and Gas Wells by Production Rate (https://www.eia.gov/petroleum/wells/), EIA's Domestic Crude Oil First Purchase Prices by Area (http://www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm), 2016 RIA Appendix A-2, ESS 2018.**
Notes: **States included are California, Colorado, Montana, North Dakota, New Mexico, South Dakota, Utah and Wyoming.**

[8] Although a temporarily shut-in well may resume operation in the future, there is no assurance that the forgone production can be recovered.

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The additional oil and gas production from marginal wells is based on the relationship between changes in marginal well production and changes in oil price.[9] As a decline in price reduces operating profit in the same manner as incremental compliance costs, the production-price relationship can be used to estimate the response of marginal wells on BLM-administered leases to the incremental compliance costs of the 2016 Rule.

Using the EIA's annual state-level reports on oil and gas wells by daily production category, the total annual oil and gas production from marginal wells[10] on BLM land declined by 2.3 MM BOE from 2014 to 2016. During the same period, crude oil first purchase prices declined sharply by $46 per barrel (approximately 45 percent) on average across the BLM states. The data imply that production from marginal wells on BLM-administered leases declined by 0.5 MM BOE for every $10 per barrel decline in price.[11]

Using the estimated production-price relationship, eliminating the average compliance cost of $6.40 per barrel of the 2016 Rule results in marginal oil and gas wells producing an additional 0.33 MM BOE. Based on average production, this is equivalent to an additional 836 marginal oil and gas wells continuing production in 2019. Normalizing production levels to those forecast in 2019 and accounting for natural attrition of existing marginal wells, the 2018 Proposed Rule will result in an additional 0.3 MM BOE on an annualized basis. Valued at $21.2 MM, the additional production value supports $8.7 million in earnings and 159 jobs nationally (Table 7).

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[9] BLM made available to the public only a subset of the ONRR lease-level data it analyzed for the 2016 RIA and 2018 RIA. The dataset did not include Indian leases, nor did it include the number of wells associated with the lease. Further, the data were available only for FY 2015—the year of analysis chosen by the BLM—preventing comparisons of marginal well production over time.

[10] Marginal wells are those producing 10 BOE per day or less.

[11] The production response is computed separately for each state using the specific change in production from marginal wells scaled to represent BLM leases and area-specific first purchase crude oil prices reported by the EIA.

Table 7: Additional Production from Marginal Oil and Gas Wells from Eliminating Provisions of the 2016 Final Rule

Production (2016 MM BOE)	Marginal Wells (#)	Production (2019 MM BOE)	Year	Production (MM BOE)	Price ($/bbl)	Value ($ MM)	Earnings ($ MM)	Jobs (#)
0.33	836	0.39						
			2019	0.39	51.76	20.2	8.27	152
			2020	0.37	65.60	24.0	9.84	181
			2021	0.34	72.27	24.8	10.14	186
			2022	0.32	75.39	24.0	9.85	181
			2023	0.30	77.74	22.9	9.40	172
			2024	0.27	78.73	21.4	8.76	161
			2025	0.25	80.85	20.0	8.21	151
			2026	0.22	81.78	18.3	7.51	138
			2027	0.20	83.30	16.7	6.84	125
			2028	0.18	84.60	14.9	6.12	112
			NPV 3%	2.47		178.6	73.2	1,342
			Annualized 3%	0.29		21.0	8.6	157
			NPV 7%	2.08		148.8	61.0	1,118
			Annualized 7%	0.30		21.2	8.7	159

Sources: Table 5, EIA 2018 Annual Energy Outlook Tables 12 and 14 (https://www.eia.gov/outlooks/aeo/), IOGCC 2015 Marginal Well Trends Report (http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/MarginalWell-2015.pdf), ESS Well Counts.
Notes: Additional production is normalized by multiplying additional production in 2016 by the ratio of EIA-forecast onshore oil and gas production in 2019 and actual 2016 production. Natural well attrition is based on estimates of the number of wells covered by the BLM rule prepared by ESS 2018. Earnings and jobs are estimated from additional production value and multipliers reported in IOGCC's 2015 Marginal Well Trend Report.

Disproportionate Impacts of Flaring Limits and Gas Capture Targets

The estimates above are a lower bound estimate because they do not account for cost impacts of meeting flaring limits and gas capture targets in the 2016 Rule. Costs of meeting flaring limits and gas capture targets disproportionately impact smaller operators. As smaller operators are more likely to be marginal producers, retaining gas capture and flaring limits will only increase the compliance cost burden on marginal producers and exacerbate premature abandonment and temporary shut-ins of marginal wells.

Using operator flaring data in the EPA's Greenhouse Gas Reporting Program (GHGRP) database, the probability of exceeding the flaring limits in the 2016 Rule declines significantly for operators with at least 50 wells when accounting for differences in oil production volume.[12]

[12] A standard logistic regression model with flaring data from the EPA's Greenhouse Gas Reporting Program (GHGRP) predicts the probability that operators exceed the gas flaring limits in the 2016 final rule based on annual oil production volume and size in terms of the number of wells. API's model assigned each of the 673 operators to one of seven well amount categories: 1, 2-4, 5-9, 10-19, 20-49, 50-99 or 100 or more.

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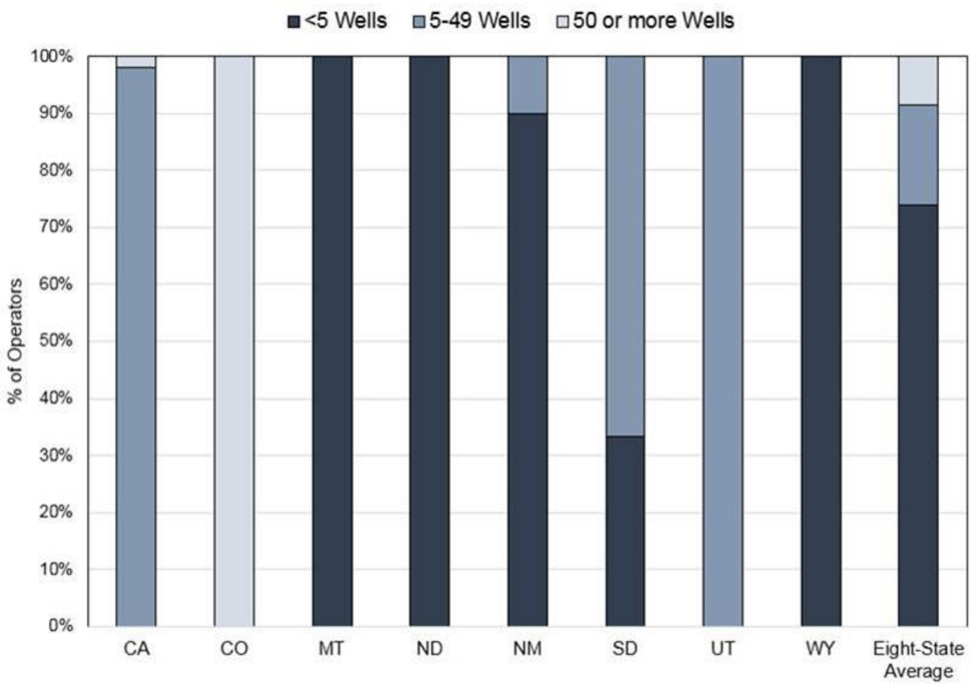
As Figure 1 demonstrates using the ONRR lease data BLM made publicly available, most operators on BLM land have fewer than 50 wells per lease.

Figure 1: Distribution of Operators in the ONRR Lease Data



4. Foregone Value of the Reduction in Emissions

The 2018 Proposed Rule will modestly increase methane emissions, and to a lesser extent than indicated in the 2018 RIA. Table 8 compares the emission reductions reported in the 2018 RIA and the estimates prepared by ESS for API. These estimates are 45,246 tons per year compared to 177,222 tons according the 2018 RIA. The foregone social value using the API estimates and the interim social cost of methane estimates are $2.9 million per year.

Table 8: Annualized Social Benefits of Emission Reductions, 2019-2028.

	Seven Percent Discount Rate		Three Percent Discount Rate	
	API Estimates	**Estimates from 2018 RIA**	**API Estimates**	**Estimates from 2018 RIA**
Average Annual Emission Reductions (tons)	45,246	177,222	45,246	177,222
Annualized Value of Foregone Emission Reductions ($millions)	$(2.9)	$(9.4)	$(8.8)	$(30.4)

The 2016 RIA used different monetary values for the social cost of methane, which did not conform with OMB guidance. Two problems associated with the social cost of methane are addressed in the 2018 RIA:

- the 2016 RIA model incorporated global costs of methane emissions whereas OMB guidance requires agencies to separately account for the costs to other countries, and
- the 2016 RIA calculated the social cost of methane using discount rates that were lower than suggested by OMB.

While these changes correct two obvious flaws, additional problems with the social cost of methane (and carbon) remain (API 2016). The costs are estimated using same underlying DICE, PAGE and FUND models that are used for previous estimates. These three impact assessment models (IAM) have not been peer-reviewed, lack a sound theoretical basis, incorporate unsupported assumptions, and yield highly uncertain estimates.

In particular, there is significant uncertainty surrounding the correlation between the temperature change and climate damage estimates. The models do not fully consider the range of variability in global population projections, specifically with uncertainty in fertility, life expectancy and migration. These socioeconomic factors have the potential to drive emissions up or down, and are not fully accounted for in the models. Additionally, the damage functions used in these models are not adequately transparent on the relationship between global temperature change and change in GDP. (EPRI 2014) Yet even though these models do not incorporate all the appropriate types of uncertainty, the range of the social cost estimates still varies by a factor of three (Marten, et. al. 2015).

Even the changes implemented for the 2018 RIA are problematic. The FUND and PAGE models both estimate methane emissions for the U.S., while the third model, DICE, uses global output. Following the methodology used to estimate the Social Cost of Carbon, the BLM estimated US emissions to be 10% of the global cost of carbon for use in the model. However, the National Academies and the interagency working group have concluded that no reliable methodologies exist for excluding non-US emissions.

Lastly, the use of a three percent discount rate produces an anomalous result, which requires further review. The social cost values attempt to reflect the impact of emissions in the year in which they occur. The present value of future releases should show declining values over time. For example, with a seven percent discount rate, the marginal cost of emissions in 2023 in 2018 dollars is $44.92, whereas an emission in 2019 has a marginal cost of $49.53 now. This means any policy that reduces emissions in 2019 is more valuable than a policy that does not start until 2023. Conversely, with a three percent discount rate, an emission reduction in 2019 is worth $166.01, while an emission reduction in 2023 is worth $166.48, which means that it is slightly more valuable to postpone an emission reduction until 2023. The amount is small and could be a rounding issue. However, a slightly different set of assumptions in the IAM models could increase the discrepancy. The key point is that low discount rates have unexplored and potentially counter-intuitive implications.

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