Attachment 14

Declaration of **Maureen Lackner and Dr. Kristina Mohlin**, Environmental Defense Fund and Exhibits A-K

IN THE UNITED STATE COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

DECLARATION OF MAUREEN LACKNER AND ANNA KRISTINA MOHLIN

We, Maureen Lackner and Anna Kristina Mohlin, declare as follows:

1. I, Maureen Lackner, am a Senior Economics and Policy Analyst, Office of the Chief Economist at Environmental Defense Fund (EDF). I earned a Master of Public Policy from the Gerald R. Ford School of Public Policy at the University of Michigan in 2017. In my work at EDF over the past three years, I have provided analysis on climate and environmental issues with a special focus on methane emissions from the oil and gas sector. My work on this issue includes economic analyses on proposed regulations and policy design, as well as modeling to track global policy ambitions and abatement opportunities. My curriculum vitae is attached as Exhibit A.

2. I, Anna Kristina Mohlin, am a Senior Economist at EDF. I have worked as an economist at EDF for 7 years. I earned a PhD in Economics from the University of Gothenburg, Sweden, in 2013 and a Master of Science in Industrial Engineering from Chalmers University of Technology, Gothenburg, in 2008. At EDF, I perform economic analysis on climate and energy policy, with a focus on electricity and natural gas markets, and provide analysis to support the organization's efforts to address methane leakage from the natural gas supply chain. I have authored or co-authored several peer-reviewed journal articles in

environmental and energy economics. My curriculum vitae is attached as Exhibit B.

EPA's Rollback of Oil and Gas Standards

3. We are aware that in 2012 and 2016, EPA promulgated requirements for regulating volatile organic compound (VOC) and methane emissions from new and modified sources in the oil and gas sector, including the transmission and storage segment of the oil and gas sector (collectively, the New Source Rule). *Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources*, 81 Fed. Reg. 35,824 (June 3, 2016); *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

4. We are also aware that EPA has now issued a rule rescinding the regulation of methane from new and modified facilities in the oil and gas sector and removing transmission and storage facilities from regulation entirely (Rescission Rule). *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review*, 85 Fed. Reg. 57,018 (Sept. 14, 2020).

5. We are aware that when EPA regulated methane from new and modified sources under the New Source Rule, it became obligated by the Clean Air Act to develop emission guidelines for methane from existing sources (Methane

Guidelines). We are likewise aware that EPA contends that the Rescission Rule removes its obligation to develop Methane Guidelines.

The Rescission Rule Eliminates Cost-Effective Requirements

6. We have reviewed portions of EPA's supporting documentation for the Rescission Rule that are relevant to this declaration, including portions of the Regulatory Impact Analysis accompanying the Rescission Rule (2020 RIA).[1] We have also reviewed portions of EPA's supporting documentation for the New Source Rule that are relevant to this declaration, including portions of the May 2016 Technical Support Document for the New Source Rule (2016 TSD)[2] and the May 2016 Regulatory Impact Analysis for the New Source Rule (2016 RIA).[3]

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[1] EPA, Regulatory Impact Analysis for the Review and Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources (Aug. 2020), *available at* https://www.epa.gov/sites/production/files/2020-08/documents/oil_and_natural_gas_nsps_review_and_reconsideration_final_ria.pdf ("2020 RIA") (excerpts attached to this Declaration as Exhibit C). Specifically, we have reviewed Sections 2.2 and 2.4 of the 2020 RIA.

[2] EPA, Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, Subpart OOOOa (May 2016), Docket ID No. EPA-HQ-OAR-2010-0505-7631 ("2016 TSD") (excerpts attached to this Declaration as Exhibit D). Specifically, we have reviewed Sections 4, 9, and 15 of the 2016 TSD.

[3] EPA, Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, *available at* https://www.epa.gov/sites/production/files/2020-07/documents/oilgas_ria_nsps_final_2016-05.pdf ("2016 RIA") (excerpts attached

7. Based on our review of these documents and our professional experience, we believe the New Source Rule emission reduction requirements that are eliminated by the Rescission Rule are feasible and cost-effective.

8. EPA itself notes that the Rescission Rule eliminates methane emission reduction requirements that are cost-effective. 85 Fed. Reg. at 57,031. For example, the New Source Rule required semi-annual leak detection and repair (LDAR) inspections for methane at regulated oil and gas facilities. The Rescission Rule will eliminate this requirement as it relates to methane.

9. In the 2016 TSD, EPA estimated that companies in the production segment spent $179 billion in new capital expenditures.[4] EPA further calculated that companies in the production segment made more than $366 billion in annual revenue.[5]

10. EPA estimated in the 2016 TSD that the total per-site annualized costs for semi-annual LDAR inspections range from $1,521 for a natural gas well site to $1,903 for an oil well site with gas-to-oil ratio of more than 300, to $2,114 for an

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to this Declaration as Exhibit E). Specifically, we have reviewed Section 6.2 of the 2016 RIA.

[4] 2016 TSD at 165 tbl.15-1.

[5] *Id.* at 165 tbl.15-2.

oil well site with a gas-to-oil ratio of less than 300.[6] These costs reflects the full cost of compliance, including the costs of completing an LDAR survey twice a year—estimated at $600 per inspection—plus other costs, including subsequent activities planning and the costs of repairs, resurvey, and reporting.[7] These values also reflect additional revenues and savings from captured natural gas due to reduced leaks.[8] These inspection estimates from the TSD are for well sites, which may contain multiple individual wells.

11. In the 2016 RIA, EPA estimated the individual per-well cost of inspections at $905 for an oil well and $1101 for a gas well.[9] This per-well cost estimate in the 2016 RIA, unlike the estimate in the TSD, does not include cost savings from recaptured natural gas, which would reduce the per-well cost further.[10]

12. In our experience and expert opinion, an annual cost of $1,521 to $2,114 per well site, or $905 to $1101 per well, is extremely small relative to the revenue generated by oil and gas wells, and such costs are unlikely to affect the decisions of companies to drill or operate oil and gas wells.

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[6] *Id.* at 48 tbl.4-10.

[7] *Id.* at 44–45.

[8] *Id.* at 48.

[9] 2016 RIA at 6-6.

[10] *Id.*

13. We have also reviewed previous analysis by EDF scientist Dr. David Lyon identifying wells subject to the standards in the New Source Rule and oil and natural gas production attributable to those wells.[11] Using well production data from Dr. Lyon's analysis, we have calculated revenue estimates for the wells subject to the New Source Rule standards, based on actual production and the average oil and gas price from the corresponding period of production from the U.S. Energy Information Administration (EIA).[12]

14. We calculated that wells drilled or modified between September 18, 2015 and April 24, 2017, the relevant time period for Dr. Lyon's data set, produced on

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[11] *See* Emergency Mot. for a Stay, or, in the Alternative, Summ. Vacatur at Attach. 5, *Clean Air Council v. Pruitt*, 862 F.3d 1 (2017) (No. 17-1145) (Declaration of Dr. David R. Lyon) (identifying wells affected by New Source Rule and their associated oil and gas production) (attached to this Declaration as Exhibit F).

[12] To calculate per-well revenue for producing oil and gas wells, we have multiplied total actual production of oil (in bbl) between September 19, 2015 and April 24, 2017 by the average Cushing price (in $/bbl) between September 19, 2015 and April 24, 2017, and for gas wells, converted total actual production between September 19, 2015 and April 24, 2017 from Mcf to MMBtu, and then multiplied by the average Henry Hub price (in $/MMBtu) between September 19, 2015 and April 24, 2017. We have then divided the total revenues from oil and gas wells by the number of producing wells. Note, estimated oil and gas production data only include months since the completion or recompletion that occurred after September 18, 2015. Average gas and oil price from Sep. 19, 2015 to April 24, 2017 obtained from EIA for Henry Hub ($2.55/MMBtu), *available at* https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm, and Cushing ($45 per barrel (bbl)), *available at* https://www.eia.gov/dnav/pet/hist/rwtcD.htm.

average more than $3 million in revenue per well, or an aggregate total of more than $42.5 billion over the nineteen months between September 18, 2015 and April 24, 2017. The relative annual per-well cost of LDAR at $905 to $1101 per year is trivial compared to per-well revenue, less than 0.06% of the average per-well revenue on an annualized basis. The size of these incremental costs shows they are unlikely to have any appreciable effect on decisions about the drilling of new wells or the operation of those wells.

15. These costs likewise represent a very small percentage of revenue for "low-production" wells. We have estimated the revenue that was generated by these "low-production" wells[13] drilled or modified between September 18, 2015 and April 24, 2017. There are 2,179 of these "low-production" wells from this period in Dr. Lyon's dataset. These wells generated on average $340,365 per well in revenue between September 18, 2015 and April 24, 2017.[14] Therefore, even for these "low-production" wells, the cost of LDAR is so small—roughly 0.5% of annualized revenue—that it would not affect decisions to drill or operate the wells.

[13] The New Source Rule defines "low production" well sites as "well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production." 81 Fed. Reg. at 35,856.

[14] Per-well revenue calculated using the same methodology described *supra* note 12.

16. In addition to this revenue analysis, we have compared LDAR costs to the costs operators would face when drilling a new well. This juxtaposition helps to contextualize the magnitude of these inspection costs when compared to the capital costs operators face drilling a new well. To do so, we have evaluated a recent report issued by the EIA that assesses capital costs for oil and gas production across the United States for the period 2006 to 2016. As reported by the EIA, during that time period, the total capital costs per onshore well ranged from $4.9 to $8.3 million.[15] These per-well capital costs far outweigh the fractional, incremental cost of LDAR estimated by EPA at $905 to $1101 per year per well. Because LDAR costs are so small relative to total capital costs, it is unlikely that LDAR compliance costs would affect decisions about whether to drill new wells, or otherwise harm producers or reduce new oil and gas development.

17. As another example, we have reviewed EPA's estimate of the costs for sources in the transmission and storage segment to comply with the New Source Rule. The Rescission Rule will remove the transmission and storage segment from regulation altogether, eliminating compliance costs for this segment.

18. In 2016, EPA estimated that capital costs incurred by transmission and storage facilities to comply with the New Source Rule would be only 0.11% of

[15] EIA, *Trends in U.S. Oil and Natural Gas Upstream Costs* at 2-5 (Mar. 2016), *available at* https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.

total capital expenditures (nearly $13 billion a year) that transmission and storage facilities would incur in the absence of the New Source Rule requirements.[16] EPA estimated that the annualized cost to these facilities of complying with the standard would be only 0.14% of estimated annual revenue (more than $26 billion) for transmission and storage facilities.[17] In our experience, a reduction in compliance costs that amounts to only 0.11% of capital expenditures and only 0.14% of annual revenue is not likely to have any significant impact on the transmission and storage sector or to affect business decisions in the sector.

Performance of the Oil and Gas Industry is Driven by Larger Macroeconomic Trends

19. In the 2020 RIA, EPA contends that the New Source Rule may have impacts on energy production and markets, and that these impacts will be reduced by the Rescission Rule.[18] In our experience, energy production and markets are affected by broad macroeconomic factors, not minor changes to the cost of regulatory compliance.

20. For example, the COVID-19 pandemic and related lockdown mandates and economic disruption have resulted in a sharp decline in demand for

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[16] 2016 TSD at 165 tbl. 15-1, 166 tbl.15-3.

[17] *Id.* at 165 tbl. 15-2, 166 tbl.15-3.

[18] 2020 RIA at 2-54 to 2-55.

oil. The EIA recognizes these market changes and predicts a decline in U.S. oil and natural gas consumption in 2020 as compared to 2019. While the EIA expects consumption to rise again in 2021, oil and gas production in 2021 is still expected to be lower than 2019 levels. Oil and gas prices follow a similar pattern.[19] Although the transmission and storage segment is somewhat insulated from price and demand volatility due to long-term agreements, volatility may affect this segment as well.[20]

21. In our experience, oil and gas companies, including transmission and storage facilities, will make decisions about production and expansion—including the decision to decrease or shut down production—based on these sector- and economy-wide factors. Small changes to compliance costs at the individual source level are not likely to factor prominently in firm decision-making.

[19] U.S. EIA, *Short-Term Energy Outlook* (Aug. 2020), https://www.eia.gov/outlooks/steo/archives/Aug20.pdf.

[20] *See, e.g.*, Jordan Blum, *US Oil Midstream Sector Enters Hibernation as Pandemic Wreaks Industry Toll*, S&P Global (June 25, 2020), https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/062520-us-oil-midstream-sector-enters-hibernation-as-pandemic-wreaks-industry-toll; *Oil Bust Is Catching Up to Pipeline Companies*, TankTerminals.com (June 15, 2020), https://tankterminals.com/news/oil-bust-is-catching-up-to-pipeline-companies/.

The Benefits of Regulatory Certainty

22. For the reasons described above, we do not anticipate that the Rescission Rule will have any substantial impact on operator costs and business decisions. However, we do anticipate that the Rescission Rule will have a negative effect on the industry by increasing regulatory uncertainty.

23. It is our experience that operators and investors prefer predictable regulatory requirements, even those that result in modest compliance costs, to constantly shifting requirements and regulatory uncertainty. Regulatory certainty allows businesses to plan into the future and make capital investments as necessary. A regulatory change that reduces compliance costs by only a minimal amount will not be enough to affect a business's bottom line, but it will contribute to an atmosphere of regulatory uncertainty that is hostile to long-term planning and investment. For example, in the wind energy industry, repeated expirations of the federal production tax credit fostered an unstable pattern of development, resulting in reduced investment.[21]

24. Feasible, cost-effective emission reduction requirements also help level the playing field. While EPA highlights voluntary methane emissions

[21] Merrill Jones Barradale, *Impact of Public Policy Uncertainty on Renewable Energy Investment: Wind Power and the Production Tax Credit*, Energy Policy vol. 38, no. 12, pp. 7698–7709 (2010), *available at* https://www.sciencedirect.com/science/article/pii/S0301421510006361.

mitigation programs in the Rescission Rule, EPA acknowledges that the industry as a whole is not meeting voluntary measures at the same level of control, and that some companies may not be participating in voluntary programs at all. 85 Fed. Reg. at 57,042. Requiring uniform emission reduction measures across the industry ensures that no single operator will be at a disadvantage due to investing in methane emission reduction measures.

25. The desire for regulatory certainty and industry-wide regulation is evident from the support major oil companies show for federal methane regulation. Companies such as ExxonMobil, Shell, and BP have expressed public support for the New Source Rule and opposition to the Rescission Rule and other efforts by EPA to remove requirements to regulate methane.[22] These companies recognize that the industry benefits from feasible, cost-effective, and predictable emissions reduction requirements.

26. Smaller companies also support federal methane regulation. For example, Pioneer Natural Resources, a Texas-based independent oil and gas exploration and production company, and Jonah Energy, an independent oil and

[22] See, e.g., Rachel Frazin, *Major Oil Companies Oppose EPA Methane Rollback*, The Hill (Aug. 14, 2020), https://thehill.com/policy/energy-environment/512097-oil-majors-oppose-epa-methane-rollback; Press Release, bp America, bp America Statement on Methane Policy Rule (Aug. 13, 2020, https://www.bp.com/en_us/united-states/home/news/press-releases/bp-america-statement-on-methane-policy-rule.html.

gas exploration and production company based in Denver with operations in Wyoming, submitted comments to EPA in support of retaining federal methane standards, explaining the importance of a "clear regulatory program [that] would provide operators with certainty and predictability in their capital spending, strategic planning and operations."[23]

27. A group of natural gas-purchasing utilities also submitted comments to EPA on the draft Rescission Rule, supporting the continued regulation of methane under the New Source Rule and the continued regulation of both VOCs and methane from transmission and storage sources.[24]

28. A group of investors with holdings in the U.S. oil and gas industry also submitted comment to EPA highlighting the strong opposition to the Rescission Rule from the investor community. The investors explained that "[m]easures to limit methane emissions are consistent with sound business

[23] Comment Letter from Gretchen Kern, Pioneer Natural Resources USA, Inc., to Amy Hambrick, EPA (Nov. 25, 2019), Docket ID No. EPA-HQ-OAR-2017-0757-1125 (attached as to this Declaration as Exhibit G); Comment Letter from Paul Ulrich, Jonah Energy LLC, to Amy Hambrick, EPA (Nov. 25, 2019), Docket ID No. EPA-HQ-OAR-2017-0757-1825 (attached to this Declaration as Exhibit H).

[24] Comment Letter from Austin Energy et al. to Hon. Andrew Wheeler, EPA (Nov. 25, 2019), Docket ID No. EPA-HQ-OAR-2017-0757-2163 (attached to this Declaration as Exhibit I).

practices and long-term company value" and urged EPA not to remove methane from regulation.[25]

Existing Sources Are Not Likely to Be Subject to Performance Standards Absent Direct Regulation

29. We are aware that in the Rescission Rule, EPA contends that even without Methane Guidelines, market incentives to capture natural gas will drive methane emission reductions.

30. While there are some economic incentives for oil and gas facilities to reduce waste of natural gas, thereby reducing methane emissions, as EPA recognizes in the 2020 RIA, the realities of the oil and gas industry may skew these incentives. For example, operators of transmission and storage facilities often do not own the natural gas they transport and store.[26] These operators will not benefit from capturing natural gas, and therefore lack the incentive to do so absent a regulatory requirement.

31. Furthermore, EPA's assertions about market incentives ignore a basic principle of economics: because methane emissions impose a negative externality

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[25] Comment Letter from Christina Herman, Interfaith Center on Corporate Responsibility, to Andrew Wheeler, EPA (Nov. 25, 2019), Docket ID No. EPA-HQ-OAR-2017-0757-0669 (attached to this Declaration as Exhibit J); *see also* Comment Letter from Austin Energy et al., *supra* note 24, at 1, 2 (noting investor interest in efforts to reduce methane throughout the natural gas supply chain).

[26] 2020 RIA at 2-25.

on society, private operators focused on maximizing their profits will not be sufficiently incentivized to reduce methane emissions to a socially-optimal level in the absence of regulation or policy which internalizes that externality.[27]

We declare that the foregoing is true and correct.

Maureen Lackner

Anna Kristina Mohlin

Dated September 14, 2020

[27] Comment letter from Catherine Hausman, Assistant Professor, Gerald R. Ford School of Public Policy, University of Michigan and Daniel Raimi, Senior Research Associate, Resources for the Future, to EPA (Oct. 18, 2019), Docket ID No. EPA-HQ-OAR-2017-0757-0083 (attached to this Declaration as Exhibit K).

Exhibit A

Maureen Lackner

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Education

University of Michigan, Gerald R. Ford School of Public Policy, Ann Arbor, MI — May 2017
Master of Public Policy

Columbia University, New York, NY — May 2013
Bachelor of Arts, Political Science and Statistics

Experience

Environmental Defense Fund, New York, NY — June 2017-Present
Senior Economics and Policy Analyst in the Office of the Chief Economist

- Design and manage a global oil and gas methane tracker in R that relies on best available data and a Monte Carlo analysis to simulate ranges of emissions and potential reductions; executive team members use the tool to track progress on methane reductions and to inform engagement strategies
- Research market-based policies to address issues such as methane abatement in the oil and gas sector, economywide emissions in the United States, and scaling new technologies
- Provide economic analyses to understand the viability of specific policy proposals; these analyses support EDF's direct engagement with policymakers at the national and state level

U.S. Government Accountability Office, Washington, D.C. — May 2016-July 2016
Applied Research and Methods Intern

- Conducted research and stakeholder interviews regarding U.S. preparedness for Zika outbreak; presented findings to internal executives to inform development of audit plan and contributed to published blog post
- Contributed to written and visual analyses and prepared descriptive data analysis that will be used in an audit of the Department of Defense pertaining to pathogens in high-containment labs

Dow Sustainability Fellows Program, Ann Arbor, MI — January 2016-December 2016
Dow Sustainability Masters Fellow

- Conducted focus groups for residents living in HOPE Village, an initiative of the non-profit Focus: HOPE
- Engaged with stakeholders from auto-industry, city government, and non-profit sector to inform analysis
- Used focus group results, GIS and census data to contribute to needs assessment and constraints analysis regarding potential for shared use mobility

The Commonwealth Fund, New York, NY — October 2013-July 2015
Grants Associate

- Developed business intelligence solutions, including a real-time budget tool used across program areas
- Coordinated development of budgets, subcontracts, and data use agreements for quarterly grant approvals

Publications and Presentations

- What do we know about methane emissions from the global oil and gas sector? 25th EAERE Annual Conference. (2020) Virtual Session. Policy Session Conference Presentation.
- Reverse Auctions: Lessons learned from renewables and storage procurement. 24th EAERE Annual Conference. (2019) The University of Manchester, Manchester, UK. Policy Session Conference Presentation.
- Policy Brief—Using Lessons from Reverse Auctions for Renewables to Deliver Energy Storage Capacity: Guidance for Policymakers. *Review of Envir. Econ. and Policy.* (2019) [With J. R. Camuzeaux and S. Koller]
- Instruments of Political Control: National Oil Companies, Oil Prices, and Petroleum Subsidies. *Comparative Political Studies.* (2014) [With J. Urpelainen and A. Cheon]
- Why Do Governments Subsidize Gasoline Consumption? An Empirical Analysis of Global Gasoline Prices, 2002-2009. *Energy Policy.* Volume 56. (2013) [With J. Urpelainen and A. Cheon]

Programming and Software Skills

Excel, R, Stata, LaTeX, ArcGIS

Exhibit B

KRISTINA MOHLIN

PROFESSIONAL EXPERIENCE

Environmental Defense Fund (EDF), New York, New York
Office of the Chief Economist

Senior Economist *April 2017 - present*
Economist *Sept 2013 - March 2017*

Chalmers University of Technology, Gothenburg, Sweden
Division of Physical Resource Theory

Research assistant *March 2008 - May 2008*

EDUCATION

Doctor of Philosophy (PhD), Economics *Sept 2008 - Sept 2013*
University of Gothenburg, Gothenburg, Sweden

Master of Science in Engineering, Industrial Eng. and Management *Aug 2003 - Jan 2008*
Chalmers University of Technology

Master's courses in Environmental Policy and Economics *Oct 2006 - July 2007*
ETH, Zurich, Switzerland

ONGOING RESEARCH PROJECTS

Rate Design and Distributed Energy Resource (DER) Integration: Impacts on the Environment and Distribution System Costs

Research project funded by the Alfred P. Sloan foundation. Collaboration between EDF, MIT Energy Initiative (MITei) and NYU, which uses a simulation framework of an electric distribution system developed at MITei. The objective is to simulate the impact of different electric rate designs on DER investment, pollution and electric distribution system costs.

PUBLICATIONS

"Turning the corner on US power sector CO_2 emissions - a 1990-2015 state level analysis" (2019) (with Alex Bi, Susanne Brooks, Jonathan Camuzeaux and Thomas Stoerk). *Environmental Research Letters*, 14, 084049.

"Factoring in the forgotten role of renewables in CO_2 emission trends using decomposition analysis" (2018) (with Jonathan Camuzeaux, Adrian Mueller, Marius Schneider and Gernot Wagner). *Energy Policy*, 116, 290-296.

"On refunding of emission taxes and technology diffusion" (2017) (with Jessica Coria). *Strategic Behaviour and the Environment*. 6 (3), 205-248.

”Designing electric utility rates: insights on achieving efficiency, equity, and environmental goals” (2017) (with Frank Convery and Beia Spiller). *Review of Environmental Economics and Policy*, 11 (1), 156-164.

”An introduction to the Green Paradox: the unintended consequences of climate policies” (2015) (with Svenn Jensen, Karen Pittel and Thomas Sterner). *Review of Environmental Economics and Policy*, 9 (2), 246-265.

”Refunded emission payments and diffusion of NOx abatement technologies in Sweden” (2015) (with Jorge Bonilla, Jessica Coria and Thomas Sterner). *Ecological Economics*, 116, 132-145.

”Putting a price on the future of our children and grandchildren” (2013) (with Maria Damon and Thomas Sterner). In: Livermore, M.A., Revesz, R.L. (eds), *The globalization of cost-benefit analysis in environmental policy*, Oxford University Press.

”Greenhouse gas taxes on animal food products: Rationale, tax scheme and climate mitigation effects” (2011) (with Stefan Wirsenius and Fredrik Hedenus). *Climatic Change*, 108 (1-2), 159-184.

”Greenhouse gas-weighted consumption taxes on food as a climate policy instrument” (2010) (with Fredrik Hedenus and Stefan Wirsenius). In: Dias Soares, C., Milne, J.E., Ashiabor, H., Kreiser, L., Deketelaere, K. (eds), *Critical issues in environmental taxation: International and comparative perspectives, Volume VIII*, Oxford University Press.

CONFERENCE PRESENTATIONS

EAERE (European Association of Environmental and Resource Economists) Annual Conference, June 2020. Online event. Conference presentation: ”Considerations for methane policy design and potential policy options”.

USAEE (United States Association for Energy Economics) Conference, November 2019. Denver, Colorado. Conference presentation: ”The Role of Rate Design in Distributed Energy Resource Deployment”.

IAEE (International Association for Energy Economics) Conference, May 2019. Montreal, Canada. Conference presentation: ”Electricity Simulations on the Distribution Edge: Developing a Granular Representation of End-user Electric Load Preferences using Smart Meter Data”.

World Congress of Environmental and Resource Economists, June 2018. Gothenburg, Sweden. Policy session organizer and presenter: ”Smart Grid for a Carbon Neutral Energy Future: the Role of Electricity Pricing and Distributed Energy Resources”.

EAERE Annual Conference, June 2017. Athens, Greece. Conference presentation: ”Determining the Factors behind the 2005-2013 Decline in U.S. Electricity Sector CO2 Emissions”.

EAERE Annual Conference, June 2015. Helsinki, Finland. Conference presentation: ”Rate Design Trends and Solar Expansion in California: Impacts of Proposed Rate Changes on Returns to Residential PV”.

World Congress of Environmental and Resource Economists, July 2014. Istanbul, Turkey. Conference presentation: ”Diffusion of NOx Abatement Technologies in Sweden”.

EAERE Annual Conference, June 2013. Toulouse, France. Conference presentation: ”On Refunding of Emission Taxes and Technology Diffusion”.

SELECT WORKSHOP, SEMINAR AND CONFERENCE ACTIVITIES

EAERE Online Policy Session: Policy design to address methane emissions from the oil and gas sector. June 2020. Online event. Session organizer and chair/moderator.

Organizer of EDF's Economics Seminar Series, 2017 - 2019

EDF Emerging Economics Issues Workshop "Leveraging next generation modeling capabilities for cost-effective decarbonization of the US energy system", August 2019. EDF, New York, New York. Workshop convener and organizer.

Pre-EAERE event: Environment and Energy Research Exchange, June 2019. EnvEcon, Dublin, Ireland. Meeting presentation: "Finding the way that works for decarbonizing US wholesale electricity markets".

IEA Global Conference on Energy Efficiency, June 2019. Dublin, Ireland. Conference participant.

NBER (National Bureau of Economic Research) Workshop on the Economics of Electricity Markets and Regulation, May 2019. Lake Tahoe, Nevada. Workshop participant.

FSR Global Forum: World Energy Transition, March 2019. Florence School of Regulation (FSR), Florence, Italy. Workshop participant.

POWER conference, March 2019. Energy Institute at Haas School of Business, University of California, Berkeley. Conference participant.

International Energy Workshop (IEW), June 2018. Gothenburg, Sweden. Workshop participant and presenter.

POWER conference, March 2018. Energy Institute at Haas School of Business, University of California, Berkeley. Conference participant.

MIT Center for Energy and Environmental Policy Research (CEEPR) Workshop, November 2017. Cambridge, Massachusetts. Workshop participant.

Exhibit C

Regulatory Impact Analysis for the Review and Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources

EPA-452/R-20-004
August 2020

Regulatory Impact Analysis for the Review and Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impacts Division
Research Triangle Park, NC

- **Employment Impacts Analysis:** The EPA expects reductions in labor associated with compliance-related activities due to this action. The EPA estimated the labor impacts due to the forgone installation, operation, and maintenance of control equipment and control activities, as well as the reductions labor associated with reduced reporting and recordkeeping requirements. The EPA estimated one-time and continual, annual labor requirements by estimating hours of labor required for compliance and converting this to full-time equivalents (FTE) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The reduction in one-time labor needed to comply with the NSPS due to this action is estimated to be about 1.2 FTE in 2021 and 2.5 FTE in 2030. The reduction in annual labor needed to comply with the NSPS due to this action is estimated at about 29 FTE in 2021 and 65 FTE in 2030. The EPA notes that this type of FTE-estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for employees who potentially lose their jobs, versus displacing jobs from other sectors of the economy.

2.1.4 Organization of the Policy Review RIA

Section 2.2 describes the estimated compliance cost reductions and forgone emissions reductions from the Policy Review, including the PV of the projected cost reductions over the 2021 to 2030 period and the associated EAV. Section 2.3 describes the projected forgone benefits resulting from this rule, including the PV and EAV over the 2021 to 2030 period. Section 2.4 describes the economic impacts expected from this action. Section 2.5 compares the projected forgone benefits and compliance cost reductions of this action, as well as a summary of the net benefits.

2.2 Projected Compliance Cost Reductions and Forgone Emissions Reductions

2.2.1 Pollution Controls and Emissions Points Assessed in this RIA

This section provides a basic description of the emissions sources and controls affected by the final Policy Review.

Fugitive Emissions Requirements: Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Pressure, changes in pressure, or mechanical stresses can also cause components or equipment to leak. Potential sources of fugitive emissions include valves, connectors, pressure relief devices, open-ended lines, flanges, closed vent systems, and thief hatches or other openings on a controlled storage vessel. These fugitive emissions do not include devices that vent as part of normal operations.

The projected cost and emission impacts assume implementation of a leak monitoring program based on the use of optical gas imaging (OGI) leak detection combined with leak correction. The monitoring and repair frequency under the baseline is quarterly for transmission and storage compressor stations.[13] This chapter presents estimates of the impacts of removing the fugitive emission requirements for compressor stations in the transmission and storage segment.

Pneumatic Controllers: Pneumatic controllers are automated instruments used for maintaining process conditions such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. Not all pneumatic controllers are gas-driven. These “non-gas-driven” pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non-gas-driven controllers are typically used. Continuous bleed pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. This chapter presents estimates of the impact of not installing low-bleed instead of high-bleed controllers to comply with the bleed limit requirement established in the 2016 NSPS for the transmission and storage segment.

Reciprocating and Centrifugal Compressors: Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. Centrifugal compressors use either wet or dry seals.

Emissions from compressors occur when natural gas leaks around moving parts in the compressor. In a reciprocating compressor, emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. Over time, during operation of the compressor, the rod packing system becomes worn and needs to be replaced to prevent excessive

[13] Monitoring frequency for compressor stations on the Alaska North Slope is annual, however, we do not estimate any compressor stations on the Alaska North Slope.

leaking from the compression cylinder. This RIA estimates the impact of removing the requirements to replace the rod packing approximately either every 3 years (36 months) or 26,000 hours in reciprocating compressors in the transmission and storage segment. As in the 2016 NSPS TSD, we assume compliance with the latter, which suggests replacement every 3.8 years for transmission sources and 4.4 years for storage sources based on operating data.

Emissions from centrifugal compressors depend on the type of seal used: either "wet," which use oil circulated at high pressure, or "dry," which use a thin gap of high-pressure gas. The use of dry gas seals substantially reduces emissions. In addition, their use significantly reduces operating costs and enhances compressor efficiency. The EPA evaluated using a mechanical dry seal system to limit or reduce the emissions from the rotating shaft of a centrifugal compressor. For centrifugal compressors equipped with wet seals, a flare was evaluated as an option for reducing emissions from centrifugal compressors. However, a review of 2016 NSPS OOOOa compliance reports submitted in 2018 from sources in several EPA Regions (3, 6, 8, 9, and 10) with the greatest oil and natural gas activity indicates that there are no affected centrifugal compressors in the transmission and storage segment.[14] As a result, we project there would be no affected centrifugal compressors in the future absent this rule, meaning there are no regulatory impacts associated with deregulating centrifugal compressors.

Storage vessels: Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically used in tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from production wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are due to the release of gas associated with daily temperature fluctuations and other equilibrium

[14] For more information on the EPA's review of the oil and natural gas NSPS compliance reports, see the docketed memorandum titled: U.S. EPA. 2020. Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards, 40 CFR Part 60, subpart OOOOa. Detailed reports are also available at: *https://www.foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-HQ-2018-001886&type=request.* Accessed April 26, 2020.

effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated under higher pressure. Typically, the larger the pressure drop, the greater the flashing emissions in the storage stage. Two ways of control tanks with significant emissions are to install a vapor recovery unit (VRU) and recover all the vapors from the tanks, or to route the emissions from the tanks to a control device. However, a review of 2016 NSPS OOOOa compliance reports submitted in 2018 from sources in the EPA Regions (3, 6, 8, 9, and 10) with the greatest oil and natural gas activity indicates that there were no storage vessels emitting more than 6 tons per year of VOC in the transmission and storage segment,[15] and therefore we presume there are no regulatory impacts associated with deregulating sources of this type.

2.2.2 Compliance Cost Analysis

There are two main steps in the compliance cost analysis. First, the EPA developed a representative or model plant for each affected emission source, point, and control option.[16] The characteristics of the model plant include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. This source-level cost and emission information for the requirements affected by this action can be found in a docketed technical memorandum associated with this action.[17] Second, the number of incrementally affected facilities for each type of equipment or facility are estimated. Changes in national-level emissions and cost estimates are calculated by multiplying the modeled source-level estimates from the first step by the number of affected facilities in each projection year from the second step. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. The estimates of national cost reductions include the value of the forgone product recovery where applicable.

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[15] Ibid.

[16] See Section 2 of the TSD accompanying this final action for more detail on how model plants were developed.

[17] U.S. EPA. 2020. Memorandum: Control Cost and Emission Changes under the Final Amendments to 40 CFR Part 60, subpart OOOOa Under Executive Order 13783.

In this section, we present the costs and emissions impacts of the Policy Review from 2021 through 2030, under the assumption that 2021 is the first full year any changes from this action will be in effect. In addition, we provide detailed analysis for 2021 and 2030, which allows the reader to draw comparisons between the first year after the promulgation of the Policy Review and nine years after the impacts have accumulated.[18] While it would be desirable to analyze impacts beyond 2030, the EPA has chosen not to, largely because of the limited information available to model long-term changes in practices and equipment use in the oil and natural gas industry. For example, the EPA has limited information on how practices, equipment, and emissions at new facilities change as they age or shut down. The current analysis assumes that newly established facilities remain in operation for the entire analysis period, which would be less realistic in a longer-term analysis. In addition, in a dynamic industry like oil and natural gas, technological progress is likely to change control methods to a greater extent over a longer time horizon, creating more uncertainty about impacts of the NSPS. For example, the current analysis does not include potential fugitive emissions controls employing remote sensing technologies currently under development.

2.2.3 Projection of Affected Facilities

To project the number of NSPS-affected facilities in transmission and storage, we first updated the number of NSPS-affected facilities for this analysis using average year-over-year increases in facility counts from the GHGI.[19] We assumed that this average number of new affected sources

[18] Any comparison of the 2016 NSPS RIA results to this analysis should be done with caution. The baseline of affected sources has been updated in this analysis, the years of analysis are different, and results in this RIA are presented in 2016 dollars, while the 2016 NSPS RIA presents results in 2012 dollars.

[19] More detailed description of the calculations on new sources are provided in Appendix A. We applied the year-by-year rate of change derived from AEO2020 oil and natural gas drilling projections to the estimated number of wells in 2014 from DrillingInfo, regardless of well type, to project the estimated number of new well sites through 2030.. In addition to well sites, the fugitive emissions requirements apply to gathering and boosting stations, transmission compressor stations, and storage compressor stations. The GHGI is used to estimate the count of newly affected compressor stations in each year. The GHGI uses a variety of data sources and studies to estimate equipment counts and emissions. Many equipment counts are based on the data reported under the GHGRP, scaled up to reflect the total population including both GHGRP-reporting and non-reporting oil and natural gas facilities. We estimated the number of new compressor stations, by type, by averaging the increases in the year-to-year changes in total national counts of equipment over the 10-year period from 2004 through 2014. Year-to-year increases were assumed to represent newly constructed facilities. Decreases in total counts were represented as zeros for that year, and average together with the annual increases. This approach results in the same number of new compressor stations in each projected year, regardless of increases or decreases in AEO projected drilling or production. The average year-to-year increase in compressor station counts are: 212 for gathering and boosting stations, 36 for transmission compressor stations, and 2 for storage compressor stations.

is constant from 2021 through 2030. While new source counts are likely to vary across years, we use this assumption as our best approximation of the average number of new sources in each year. See Appendix A for details on activity count projections.

Over time, facilities are constructed or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates.[20] This analysis assumes that all projected new sources from 2015 through 2029 are still in operation in 2030. These sources include fugitive emissions sources at compressor stations, pneumatic controllers, and centrifugal and reciprocating compressors.[21]

Table 2-3 shows the projected number of NSPS-affected sources in each year. The estimates for affected sources are based upon projections of new sources alone, and do not include replacement or modification of existing sources. While some of these sources are unlikely to be modified, the impact estimates may be underestimated due to the focus on new sources. For compressor stations and reciprocating compressors, newly constructed affected facilities are estimated based on averaging year-to-year changes in activity data in the GHGI between 2004 and 2014. The approach averages the number of newly constructed units in all years. In years when the total count of equipment decreased, there were assumed to be no new units. For pneumatic controllers, we use the same averaging technique applied to 2011 to 2014 GHGI data, since the Inventory did not disaggregate pneumatic controllers into high and low bleed prior to 2011.[22] We assume there are no new wet seal centrifugal compressors or affected storage vessels based on the assessment of the recent NSPS oil and natural gas compliance reports.[23]

[20] This RIA provides more detailed information than previous oil and natural gas NSPS RIA analyses by including year-by-year results over the 2021 to 2030 analysis period.

[21] Due to data limitations, we do not quantify any emissions or cost changes associated with new compressor stations on the Alaska North Slope.

[22] Based on comment received on the proposal of this rule, we treat the installation of low-bleed pneumatic controllers from 2015 to 2020 as irreversible, meaning that they are not assumed to be replaced with high-bleed controllers as a result of this action until the end of their assumed equipment lifetime.

[23] For more information on the EPA's review of the oil and natural gas NSPS compliance reports, see the docketed memorandum titled: U.S. EPA. 2020. Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards, 40 CFR Part 60, subpart OOOOa. Detailed reports are also available at: *https://www.foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-HQ-2018-001886&type=request.* Accessed April 26, 2020.

Table 2-3 Projected NSPS-Affected Sources in Transmission and Storage, 2021–2030[24]

Year	Compressor Stations	Reciprocating Compressors	Centrifugal Compressors	Pneumatic Controllers[1]	Storage Vessels	Total
2021	270	530	0	310	0	1,100
2022	300	610	0	620	0	1,500
2023	340	680	0	920	0	2,000
2024	380	760	0	1,200	0	2,400
2025	420	840	0	1,500	0	2,800
2026	460	910	0	1,800	0	3,200
2027	490	990	0	2,200	0	3,600
2028	530	1,100	0	2,500	0	4,100
2029	570	1,100	0	2,800	0	4,500
2030	610	1,200	0	3,400	0	5,200

Note: Estimates may not sum due to independent rounding
[1] Counts in this column do not include pneumatic controllers installed between 2015 and 2020, which are affected sources under the NSPS but are not expected to change activities as a result of this action until the end of their assumed equipment lifetimes.

There have been multiple updates to the GHGI, and the data the EPA used to estimate the number of affected sources in the 2016 NSPS OOOOa was revised where appropriate. We updated the time period used to estimate the number of affected sources. The 2016 NSPS RIA used the ten-year period leading up to 2012, whereas this proposed action estimates the number of affected sources in the ten-year period leading up to 2014. The projected number of affected sources in the transmission and storage segment is sensitive to the ten-year period used for averaging. For example, the 2016 NSPS RIA estimated four new transmission compressor stations a year, and this analysis estimates 36 new transmission compressor stations per year. Though the difference in the count of affected sources as estimated for the 2016 NSPS RIA and the Policy Review is large, when compared to the total number of transmission compressor

[24] See Appendix A for more discussion. Nationwide impacts of certifications for closed vent system design and technical infeasibility of routing pneumatic pumps to an existing control device, rod-packing replacements at reciprocating compressors, route-to-control measures for wet-seal centrifugal compressors, and use of low-bleed pneumatic controllers were calculated by estimating the count of affected facilities installed in a typical year and then using that typical year estimate to estimate the number of new affected facilities for each of the years in the study period, 2021 through 2030. The basis for the counts of affected facilities that would require closed vent system and technical infeasibility certifications in a typical year was information from 2016 NSPS OOOOa compliance information for 2017. These represent the number of new affected facilities in a "typical year." The GHGI was used to generate counts of reciprocating compressors and pneumatic controllers in transmission and storage only. The 2017 compliance report's nationwide number of new affected facilities reported are: 663 pneumatic pumps, 180 reciprocating compressors, 0 centrifugal compressors, 697 storage vessels and 308 pneumatic controllers

stations nationally in 2014 (about 1,800), both are small: 0.2 percent and 2.0 percent, respectively.

In addition, since the 2016 NSPS RIA (which used 2015 GHGI data), the EPA updated the GHGI methodology used to develop station counts. This update had only a small impact on total national counts in the GHGI.[25] The update also resulted in minor changes in year-to-year trends, which have impacted the affected source projection. National estimates of other sources (*e.g.*, compressors and pneumatic controllers) in the transmission and storage segment rely on station counts as an input and are therefore impacted by this change as well. As annual national counts of transmission and storage stations are not directly available from any national-level data source, the EPA applies a methodology to estimate the total national counts of transmission and storage stations. This method was updated between the 2015 GHGI and the 2018 GHGI. For the 2016 NSPS, (using the previous GHGI methodology) transmission station counts were estimated by applying a factor of stations per mile of transmission pipeline to the total national transmission pipeline mileage.[26] Storage station counts were also developed using the previous GHGI methodology (applying a factor of stations per unit of gas consumption to total national gas consumption). In this RIA, transmission station counts are developed using updated data from the 2018 GHGI. In the 2018 GHGI, transmission stations are estimated based on scaled-up Greenhouse Gas Reporting Program (GHGRP) data. Storage stations are estimated by applying a factor to total national storage fields. These improvements to the methods were developed with stakeholder input.

2.2.4 Forgone Emissions Reductions

Table 2-4 summarizes the forgone emissions reductions associated with the Policy Review. The forgone emissions reductions are estimated by multiplying the source-level forgone emissions

[25] For example, the 2018 GHG Inventory estimate of station counts in 2013 is 5 percent lower for transmission stations and 12 percent lower for storage stations.

[26] The EPA used the GHGRP subpart W station count scaled by a factor of 3.52 to adjust for GHGRP coverage. In 2016 for example, 529 transmission stations reported to GHGRP, and the national GHG Inventory calculated 1,862 transmission stations as the national total.

reductions associated with each applicable control and facility type by the number of affected sources of that facility type.[27]

Table 2-4 Projected Forgone Emissions Reductions from Policy Review, 2021–2030

	Emission Changes			
Year	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq.)**
2021	22,000	610	18	500,000
2022	26,000	720	21	590,000
2023	30,000	830	25	680,000
2024	34,000	940	28	770,000
2025	38,000	1,000	31	860,000
2026	42,000	1,200	34	940,000
2027	46,000	1,300	37	1,000,000
2028	49,000	1,400	41	1,100,000
2029	53,000	1,500	44	1,200,000
2030	58,000	1,600	48	1,300,000
Total	400,000	11,000	330	9,000,000

Note: Estimates may not sum due to independent rounding.

2.2.5 Forgone Product Recovery

The projected compliance cost reductions presented below include the forgone revenue from the reductions in natural gas recovery projected under the Policy Review. Requirements for compressor stations, reciprocating compressors, and pneumatic controllers are assumed to increase the capture of methane and VOC emissions that would otherwise be vented to the atmosphere, and we assume that a large proportion of the averted methane emissions can be directed into natural gas production streams and sold.

Table 2-5 summarizes the decrease in natural gas recovery and the associated forgone revenue. The AEO2020 projects Henry Hub natural gas prices rising from $2.49/MMBtu in 2021 to $3.29/MMBtu in 2030 in 2019 dollars.[28] To be consistent with other financial estimates in the

[27] For more information on the EPA's review of the oil and natural gas NSPS compliance reports, see the docketed memorandum titled: U.S. EPA. 2020. Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards, 40 CFR Part 60, subpart OOOOa. Detailed reports are also available at: *https://www.foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-HQ-2018-001886&type=request.* Accessed April 26, 2020.

[28] Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm. Accessed April 26, 2020

RIA, we adjust the projected prices in AEO2020 from 2019 dollars to 2016 dollars using the GDP-Implicit Price Deflator. We also adjust prices for the wellhead using an EIA study that indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price, [29] and therefore we use a conversion factor of 1.036 MMBtu equals 1 Mcf. Incorporating these adjustments, wellhead natural gas prices are assumed to rise from $2.20/Mcf in 2021 to $2.89/Mcf in 2030.

Table 2-5 Projected Decrease in Natural Gas Recovery for Policy Review, 2021–2030

Year	Decrease in Gas Recovery (Tcf)	Forgone Revenue (millions 2016$)
2021	1.3	$2.5
2022	1.5	$3.0
2023	1.7	$3.4
2024	2.0	$4.0
2025	2.2	$4.9
2026	2.4	$5.8
2027	2.6	$6.7
2028	2.9	$7.5
2029	3.1	$8.1
2030	3.4	$8.7

Operators in the transmission and storage segment of the industry do not typically own the natural gas they transport; rather, they receive payment for the transportation service they provide. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in a national-level analysis. An economic argument can be made that, in the long run, no single entity bears the entire burden of compliance costs or fully appropriates the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is likely to be spread across different market participants. Therefore, the simplest and most transparent option for allocating these revenues would be to keep the compliance costs and revenues within a given source category and not make assumptions regarding the allocation of costs and revenues across agents. [30]

[29] See: https://www.researchgate.net/publication/265155970_US_Natural_Gas_Markets_Relationship_Between_Henry_Hub_Spot_Prices_and_US_Wellhead_Prices. Accessed 04/26/2020.

[30] As a sensitivity, we calculated forgone natural gas revenues using the Henry Hub price instead of the estimated wellhead price, as the former may better reflect the value of natural gas in the transmission and storage segment.

2.2.6 Compliance Cost Reductions

Table 2-6 summarizes the compliance cost reductions and forgone revenue from product recovery for the evaluated emissions sources and points. Total cost reductions consist of capital cost reductions; annual operating and maintenance cost reductions, including reporting and recordkeeping costs;[31] and forgone revenue from product recovery. Capital cost reductions include the capital cost reductions from removing the requirements on newly affected controllers and compressors and the planning cost reductions from removing requirements for compressor stations to create survey monitoring plans for the fugitive emissions, as well as the cost reductions for sources that would have had to renew survey monitoring plans or purchase new capital equipment at the end of its useful life. The annual operating and maintenance cost reductions are due to the fugitives monitoring requirement and other reporting and recordkeeping requirements.

Under this alternative fuel price assumption, the forgone revenue associated with unrecovered natural gas is $3.4 million in 2021 and $10.4 million in 2030.

[31] Reporting and recordkeeping cost reductions not due to changes in the fugitive emissions monitoring requirements were drawn from the information collection request (ICR) that have been submitted to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see preamble for more detail). These reporting and recordkeeping cost reductions are estimated to be about $210,000 in 2021 and increasing to about $330,000 in 2030. Reporting and recordkeeping cost reductions for fugitive emissions monitoring requirements are captured directly as operating and maintenance cost reductions associated with that program. Recordkeeping and recordkeeping cost reductions are estimated for the Policy Review for all affected facilities regardless of whether they are in states with regulatory requirements similar to the final 2016 NSPS OOOOa.

Table 2-6 Estimated Cost Reductions under the Policy Review, 2021–2030 (millions 2016$)

Year	Compliance Cost Reductions				
	Capital Cost Reductions[1]	Operating and Maintenance Cost Reductions	Annualized Cost Reductions (w/o Forgone Revenue)[2]	Forgone Revenue from Product Recovery	Annualized Cost Reductions (with Forgone Revenue)
2021	$1.9	$4.2	$6.2	$2.5	$3.7
2022	$1.9	$4.8	$7.1	$3.0	$4.1
2023	$3.2	$5.4	$8.0	$3.4	$4.5
2024	$3.2	$5.9	$8.8	$4.0	$4.8
2025	$3.2	$6.5	$10	$4.9	$4.8
2026	$3.2	$7.1	$11	$5.8	$4.7
2027	$3.6	$7.7	$11	$6.7	$4.7
2028	$3.6	$8.3	$12	$7.5	$4.9
2029	$3.6	$8.9	$13	$8.1	$5.1
2030	$3.7	$9.5	$14	$8.7	$5.4

Note: Sums may not total due to independent rounding.
[1] The capital cost reductions include the planning cost reductions for newly affected sources for fugitive emissions monitoring and capital cost reductions for newly affected controllers and compressors, as well as the cost reductions for sources that would renew survey monitoring plans and purchase new capital at the end of its useful life.
[2] These cost reductions include the capital cost reductions annualized over the requisite equipment lifetimes at an interest rate of 7 percent and the annual operating and maintenance cost reductions for every year, which include the cost reductions from recordkeeping and reporting.

The cost of designing, or redesigning, a fugitive emissions monitoring program occurs every eight years to comply with the 2016 NSPS OOOOa. Pneumatic controllers are assumed to have a lifetime of ten years. Rod packing replacement is assumed to happen about every 3.8 years in the transmission segment and every 4.4 years in the storage segment.[32] The lifetime of the sources affected by this action are unchanged from the assumptions used for the 2016 NSPS OOOOa. The reduction in capital costs in each year outlined in Table 2-6 includes the estimated reduction in costs for newly affected sources in that year, plus the reduction in costs for sources affected previously that have reached the end of their assumed economic lifetime.

The capital and planning cost reductions for reciprocating compressors, pneumatic controllers, and fugitive emissions monitoring program design are annualized over their requisite expected lifetimes at an interest rate of 7 percent and are added to the annual operating and maintenance cost reductions of the requirements to get the annualized cost reductions in each year. The

[32] For the purposes of assigning unannualized capital costs of subsequent replacements to years, we round the lifetimes for rod packing in both transmission and storage to four years.

forgone value of product recovery is then subtracted to get the total annualized cost reductions in each year.

Table 2-7 illustrates the sensitivity of the estimated cost reductions to a given interest rate. We present cost reductions using interest rates of 7 and 3 percent. The choice of interest rate has a very small effect on nationwide annualized cost reductions. The interest rate generally affects estimates of annualized costs for controls with high planning or capital costs relative to annual costs. In this analysis, the planning and capital cost reductions are small relative to the annual operating and maintenance cost reductions, so the interest rate has little impact on total annualized cost reductions for these sources.

Table 2-7 Estimated Cost Reductions for the Policy Review, 2021–2030 (millions 2016$)

	7 percent			3 percent		
Year	**Annualized Cost Reductions (w/o Forgone Revenue)**	**Forgone Revenue from Product Recovery**	**Annualized Cost Reductions (with Forgone Revenue)**	**Annualized Cost Reductions (w/o Forgone Revenue)**	**Forgone Revenue from Product Recovery**	**Annualized Cost Reductions (with Forgone Revenue)**
2021	$6.2	$2.5	$3.7	$6.0	$2.5	$3.4
2022	$7.1	$3.0	$4.1	$6.8	$3.0	$3.9
2023	$8.0	$3.4	$4.5	$7.6	$3.4	$4.2
2024	$8.8	$4.0	$4.8	$8.5	$4.0	$4.5
2025	$10	$4.9	$4.8	$9.3	$4.9	$4.4
2026	$11	$5.8	$4.7	$10	$5.8	$4.3
2027	$11	$6.7	$4.7	$11	$6.7	$4.3
2028	$12	$7.5	$4.9	$12	$7.5	$4.4
2029	$13	$8.1	$5.1	$13	$8.1	$4.6
2030	$14	$8.7	$5.4	$14	$8.7	$4.9

Note: Estimates may not sum due to independent rounding.

2.2.7 Detailed Impacts Tables

The following tables show the full details of the cost reductions and forgone emissions reductions by emissions source in 2021 and 2030.

Two of the affected source types, reciprocating compressors and pneumatic controllers, have negative cost reductions, meaning that the potential capital and annual cost reductions from deregulating the transmission and storage segment may be outweighed by the forgone revenue from product recovery. This observation may typically support an assumption that operators would continue to perform the emissions abatement activity, regardless of whether a requirement is in place, because it is in their private self-interest. However, as discussed in the 2016 RIA, operators in the transmission and storage segment of the industry do not typically own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, financial incentives to reduce emissions may be minimal because operators are not able to recoup the financial value of captured natural gas that may otherwise be emitted. Alternatively, there may also be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emission of pollutants) that is not reflected in the control costs. If environmental investment displaces investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement to the regulated entity. To the extent that any opportunity costs are not added to the control costs, the compliance cost reductions presented above may be underestimated.

Table 2-8 Affected Sources, Forgone Emissions Reductions, and Compliance Cost Reductions for the Policy Review, 2021

		Forgone Emissions Reductions				Compliance Cost Reductions (millions $2016)			
Source/Emissions Points in Transmission and Storage	Projected No. of Affected Sources	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	Annualized Capital Cost Reductions	Operating and Maintenance Reductions	Forgone Product Recovery	Total Annualized Cost Reductions with Forgone Revenue
Fugitive Emissions - Compressor Stations	270	9,700	270	8.0	220,000	$1.00	$4.0	$1.1	$3.9
Reciprocating Compressors	530	12,000	320	9.5	260,000	$0.99	$0	$1.3	-$0.32
Centrifugal Compressors	0	0	0	0	0	$0	$0	$0	$0
Pneumatic Controllers	310	860	24	0.7	19,000	$0.008	$0	$0.10	-$0.09
Reporting and Recordkeeping[1]	N/A	0	0	0	0	$0	$0.21	$0	$0.21
TOTAL	**1,100**	**22,000**	**610**	**18**	**500,000**	**$2.0**	**$4.2**	**$2.5**	**$3.7**

Note: Estimates may not sum due to independent rounding.
[1] Applies to reporting and recordkeeping for requirements other than the fugitive emissions monitoring requirements.

Table 2-9 Affected Sources, Forgone Emissions Reductions, and Compliance Cost Reductions for the Policy Review, 2030

		Forgone Emissions Reductions				Compliance Cost Reductions (millions $2016)			
Source/Emissions Points in Transmission and Storage	Projected No. of Affected Sources	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO_2 Eq.)	Annualized Capital Cost Reductions	Operating and Maintenance Reductions	Forgone Product Recovery	Total Annualized Cost Reductions with Forgone Revenue
Fugitive Emissions - Compressor Stations	610	22,000	620	18	500,000	$2.3	$9.1	$3.3	$8.1
Reciprocating Compressors	1,200	26,000	730	22	600,000	$2.3	$0	$3.9	-$1.7
Centrifugal Compressors	0	0	0	0	0	$0	$0	$0	$0
Pneumatic Controllers	3,400	9,400	260	8	210,000	$0.09	$0	$1.4	-$1.3
Reporting and Recordkeeping[1]	N/A	0	0	0	0	$0	$0.33	$0	$0.33
TOTAL	**5,200**	**58,000**	**1,600**	**48**	**1,300,000**	**$4.7**	**$9.1**	**$8.7**	**$5.4**

Note: Estimates may not sum due to independent rounding.
[1] Applies to reporting and recordkeeping for requirements other than the fugitive emissions monitoring requirements.

2.2.8 Present Value and Equivalent Annualized Value of Cost Reductions

This section presents the compliance cost reductions of the Policy Review in a PV framework. The stream of the estimated cost reductions for each year from 2021 through 2030 is discounted back to 2020 using 7 and 3 percent discount rates and summed to get the PV of the cost reductions. The PV is then used to estimate the EAV of the cost reductions. The EAV is the single annual value which, if summed in PV terms across years in the analytical time frame, equals the PV of the original (*i.e.*, likely time-varying) stream of cost reductions. In other words, the EAV takes the potentially "lumpy" stream of cost reductions and converts them into a single value that, when discounted and added together over each period in the analysis time frame, equals the original stream of values in PV terms.

Table 2-10 shows the undiscounted stream of cost reductions for each year from 2021 through 2030 due to the Policy Review. Capital cost reductions are the projected capital and planning costs which will no longer be incurred. Total cost reductions are the sum of the capital cost reductions, annual operating cost reductions, and reporting and recordkeeping cost reductions. The forgone revenue from the decrease in product recovery is estimated using the AEO2020 natural gas price projections, as described earlier. Total cost reductions with forgone revenue equals the total cost reductions minus the forgone revenue. Over time, with the addition of new affected sources in each year, the capital cost reductions, annual operating cost reductions, reporting and recordkeeping cost reductions, and forgone revenue increase.

Table 2-10 Undiscounted Projected Compliance Cost Reductions for the Policy Review, 2021–2030 (millions 2016$)

Year	Capital Cost Reductions	Annual Operating Cost Reductions	Total Cost Reductions (w/o Forgone Revenue)	Forgone Revenue from Product Recovery	Total Cost Reductions (with Forgone Revenue)
2021	$1.9	$4.0	$6.1	$2.5	$3.5
2022	$1.9	$4.6	$6.6	$3.0	$3.7
2023	$3.2	$5.1	$8.5	$3.4	$5.1
2024	$3.2	$5.7	$9.1	$4.0	$5.1
2025	$3.2	$6.3	$10	$4.9	$4.8
2026	$3.2	$6.8	$10	$5.8	$4.5
2027	$3.6	$7.4	$11	$6.7	$4.6
2028	$3.6	$8.0	$12	$7.5	$4.5
2029	$3.6	$8.5	$13	$8.1	$4.4
2030	$3.7	$9.1	$13	$8.7	$4.5

Note: Estimates may not sum due to independent rounding.

Table 2-11 shows the discounted stream of cost reductions discounted to 2020 using a 7 percent discount rate. The PV of total compliance cost reductions is $31 million, with an EAV of $4.1 million per year. The PV of the stream of cost reductions discounted to 2020 using a 3 percent discount rate is $38 million, with an EAV of $4.3 million per year.

Table 2-11 Discounted Cost Reductions for the Policy Review using 7 and 3 Percent Discount Rates (millions 2016$)[1]

	7 Percent			3 Percent		
Year	Total Annual Cost Reductions (w/o Forgone Revenue)	Forgone Revenue from Product Recovery	Total Cost Reductions (with Forgone Revenue)	Total Annual Cost Reductions (w/o Forgone Revenue)	Forgone Revenue from Product Recovery	Total Cost Reductions (with Forgone Revenue)
2021	$5.7	$2.4	$3.3	$5.9	$2.4	$3.4
2022	$5.8	$2.6	$3.2	$6.2	$2.8	$3.5
2023	$7.0	$2.8	$4.2	$7.8	$3.1	$4.7
2024	$7.0	$3.1	$3.9	$8.0	$3.6	$4.5
2025	$6.9	$3.5	$3.4	$8.3	$4.2	$4.2
2026	$6.9	$3.9	$3.0	$8.5	$4.9	$3.7
2027	$7.1	$4.2	$2.9	$9.1	$5.5	$3.8
2028	$6.9	$4.3	$2.6	$9.3	$5.9	$3.5
2029	$6.8	$4.4	$2.4	$9.4	$6.2	$3.4
2030	$6.7	$4.4	$2.3	$10	$6.5	$3.3
PV	**$67**	**$36**	**$31**	**$83**	**$45**	**$38**
EAV	**$8.9**	**$4.7**	**$4.1**	**$9.4**	**$5.1**	**$4.3**

Note: Estimates may not sum due to independent rounding.
[1] Cost reductions and forgone revenue in each year are discounted to 2020.

The Policy Review is considered a deregulatory action under E.O. 13771, Reducing Regulation and Controlling Regulatory Costs. The PV of the projected cost reductions from the Policy Review calculated in accordance with E.O. 13771 accounting standards are $45 million over an infinite time horizon (in 2016$, discounted to 2016 at 7 percent). The EAV of the cost reductions over an infinite time horizon are $3.2 million per year (in 2016$, discounted to 2016 at 7 percent).

2.3 Forgone Benefits

2.3.1 Introduction

For the oil and natural gas sector NSPS promulgated in 2012 and 2016, the EPA projected climate and ozone benefits from methane reductions, ozone and fine particulate matter ($PM_{2.5}$) health benefits from VOC reductions, and health benefits from ancillary HAP reductions. These benefits were expected to occur because the control techniques to meet the standards fatigue, tremors, and impaired motor coordination (ATSDR, 2007). The EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

2.3.6.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore The EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.

2.3.6.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in the EPA's IRIS database.[54]

2.4 Economic Impacts and Distributional Assessments

This section includes four sets of discussion for this final action: energy markets impacts, distributional impacts, small business impacts, and employment impacts.

2.4.1 Energy Markets Impacts

As it is implemented, the 2016 NSPS OOOOa may have impacts on energy production and markets, which would be reduced by the finalized Policy Review. For the 2016 NSPS RIA, The EPA used the National Energy Modeling System (NEMS) to project drilling activity, price, and

[54] U.S. EPA Integrated Risk Information System (IRIS) database is available at www.epa.gov/iris. Accessed April 26, 2020

quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas national energy markets as a result of the 2016 NSPS OOOOa.[55] In that analysis, the EPA estimated the following impacts under the final 2016 NSPS OOOOa:

- Natural gas and crude oil drilling levels would decline slightly over the 2020 to 2025 period (by about 0.17 percent for natural gas wells and 0.02 percent for crude oil wells);
- Crude oil production would not change appreciably under the rule, while natural gas production would decline slightly over the 2020 to 2025 period (about 0.03 percent);
- Crude oil wellhead prices for onshore production in the lower 48 states were not estimated to change appreciably over the 2020 to 2025 period, while wellhead natural gas prices for onshore production in the lower 48 states were estimated to increase slightly over the 2020 to 2025 period (about 0.20 percent); and,
- Net imports of natural gas were estimated to increase slightly in 2020 (by about 0.12 percent) and in 2025 (by about 0.11 percent), while net imports of crude oil were not estimated to change appreciably over the 2020 to 2025 period.

As described earlier in this RIA, this final action removes requirements in the 2016 NSPS OOOOa for sources in the transmission and storage segment. The finalized Policy Review is expected to lead to cost reductions compared to the baseline. As a result, the EPA expects this final action to reduce the impacts associated with the 2016 NSPS.

2.4.2 Distributional Impacts

The cost reductions and forgone benefits presented above are not expected to be distributed uniformly across the population. OMB recommends including a description of distributional effects in regulatory analysis, "so that decision makers can properly consider them along with the effects on economic efficiency [*i.e.*, net benefits]. Executive Order 12866 authorizes this approach." (U.S. Office of Management and Budget 2003). Understanding the distribution of the compliance cost reductions and forgone benefits can reveal community-level impacts associated

[55] See Section 6.2 of the 2016 NSPS RIA.

with regulatory actions. This section discusses the general expectations regarding how cost reductions might be distributed across affected entities and how forgone health benefits might be distributed across the U.S. informed by a review of recent literature. The EPA did not conduct a quantitative assessment of these distributional impacts for the final Policy Review, but this section provides a qualitative discussion of the types of distributional impacts that could result from this final action.

2.4.2.1 Distributional Aspects of Compliance Cost Reductions

The compliance costs associated with an environmental regulation can impact households by raising the prices of goods and services; the extent of the price increase depends on if and how producers pass-through those costs to consumers. The literature evaluates the distributional effects of introducing a new regulation; for this action, which is deregulatory, these effects can generally be interpreted in reverse. Expenditures on energy are usually a larger share of low-income household income than that of other households, and this share falls as income increases. Therefore, policies that increase energy prices have been found to be regressive, placing a relatively higher burden on lower income households (*e.g.*, Burtraw et al., 2009; Hassett et al., 2009; Williams et al. 2015). However, compliance costs will not be solely passed on in the form of higher energy prices, but also through lower labor earnings and returns to capital in the sector. Changes in employment associated with lower labor earnings can have distributional consequences depending on several factors (Section 2.4.4 discusses employment effects further). Capital income tends to make up a greater proportion of overall income for high income households. As a result, the costs passed through to households via lower returns to capital tend to be progressive, placing a greater share of the burden on higher income households in these instances (Rausch et al., 2011; Fullerton et al., 2012).

The ultimate distributional outcomes of a regulation will depend on how changes in energy prices and lower returns to labor and capital propagate through the economy and interact with existing government transfer programs. Some studies that use economy-wide frameworks find that the overall distribution of compliance costs could be progressive for some policies due to the changes in capital payments and the expectation that existing government transfer indexed to inflation will offset the burden to lower income households (Fullerton et al., 2011; Blonz et al., 2012).[56] However, others have found the distribution of compliance costs to be regressive due to a dominating effect of changes in energy prices to consumers (Fullerton 2011; Burtraw, et. al., 2009; Williams, et al., 2015). There may also be significant heterogeneity in the costs borne by individuals within income deciles (Rausch et al., 2011; Cronin et al., 2019). Different classifications of households, such as those based on lifetime income rather than contemporaneous annual income, may indicate notably different results in a distributional analysis (Fullerton and Metcalf, 2002; Fullerton et al., 2011). Furthermore, there may be important regional differences in the incidence of regulations. There are differences in the composition of goods consumed, regional production methods, the stringency of a rule, as well as the location of affected labor and capital ownership (the latter of which may be foreign-owned) (*e.g.* Caron et al. 2017; Hassett et al. 2009).

2.4.2.2 Distributional Aspects of the Forgone Health Benefits

This section discusses the distribution of forgone health benefits that result from the final Policy Review. The EPA guidance directs analysts to first consider the distribution of impacts in the baseline, prior to any regulatory action (U.S. EPA 2016). Often the baseline incidence of health problems is higher in low-income or minority populations due to a variety of factors, including the tendency for more pollution sources to be located in areas where low-income and minority populations live, work, and play (Bullard, et al. 2007; United Church of Christ 1987); greater susceptibility to a given exposure level due to physiology or other triggers (Akinbami 2012); and higher incidence of pre-existing conditions (Schwartz et al 2011). EPA (2016) recommends analysts examine the distribution of health impacts under the regulatory options being considered. Finally, after assessing the differences between the baseline and policy scenario, analysts should take note of whether the action ameliorates or exacerbates any pre-existing disparities.

Because regulatory health impacts are distributed based on the degree to which housing and work locations overlap geographically with areas where atmospheric concentrations of pollutants

[56] The incidence of government transfer payments (*e.g.*, Social Security) is generally progressive because these payments represent a significant source of income for lower income deciles and only a small source for high income deciles. Government transfer programs are often, implicitly or explicitly, indexed to inflation. For example, Social Security payments and veterans' benefits are adjusted every year to account for changes in prices (*i.e.*, inflation).

change, it is difficult to fully know the distributional impacts of a rule. Air dispersion models provide some information on changes in air quality induced by regulation, but it may be difficult to identify the characteristics of populations in those affected areas, as well as to perform local air dispersion modeling nationwide. Furthermore, the overall distribution of health benefits will depend on whether and how households engage in averting behaviors in response to changes in air quality, *e.g.*, by moving or changing the amount of time spent outside (Sieg et al., 2004).

2.4.3 Small Business Impacts

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104121), requires that whenever an agency publishes a proposed rule, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. §605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. An IRFA describes the economic impact of the rule on small entities and any alternative options that would accomplish the objectives of the rule while minimizing economic impacts on small entities.

An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. As the Policy Review eliminates the regulatory requirements of the oil and natural gas sector NSPS for all transmission and storage sources, we have concluded that this final action will relieve regulatory burden for affected small entities in the transmission and storage segment that would otherwise be subject to requirements under the baseline.

2.4.4 Employment Impacts

We analyzed the impacts of the Policy Review on employment, which are discussed in this section.[57] This analysis uses detailed engineering information on labor requirements for the

[57] The employment analysis in this RIA is part of the EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

rescinded provisions in order to estimate partial employment impacts for affected entities in the oil and natural gas industry. These bottom-up, engineering-based estimates represent only one portion of potential employment impacts within the regulated industry and do not represent estimates of the *net* employment impacts of this rule. Due to data and methodological limitations, other potential employment impacts in the affected industry and impacts in related industries could not be estimated. First, this section presents an overview of the various ways that environmental regulation can affect employment. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is reasonable and informative. The section concludes with estimates of partial employment impacts based on engineering-based information for labor requirements.

2.4.4.1 Employment Impacts of Environmental Regulation

E.O. 13777 directs federal agencies to consider a variety of issues regarding the characteristics and impacts of regulations, including the effect of regulations on jobs (Executive Order 13777). Employment impacts of environmental regulations are composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes.

Environmental regulation "typically affects the distribution of employment among industries rather than the general employment level" (Arrow *et. al.* 1996). Even if impacts are small after long-run market adjustments to full employment, many regulatory actions have transitional effects in the short run (OMB, 2015). These movements of workers in and out of jobs in response to environmental regulation are potentially important and of interest to policymakers. Transitional job losses have consequences for workers that operate in declining industries, have limited capacity to migrate, or live in communities or regions with high unemployment rates.

As rescinding the oil and natural gas NSPS for transmission and storage segment is likely to cause little change in oil and natural gas exploration and production (and the production and processing segment continues to be regulated by the NSPS), demand for labor employed in exploration and production and associated industries is unlikely to change much, if at all. For affected oil and natural gas entities, some may reduce the labor they allocate to compliance-related activities associated with the now-rescinded oil and natural gas NSPS requirements for the transmission and storage segment.

2.4.4.2 Estimates of Reduction in Labor Required to Comply

The focus of this part of the analysis is on changes in the compliance-related labor requirements resulting from the removal of the requirements for the transmission and storage segment from the oil and natural gas NSPS. This analysis estimates the incremental change in labor required to satisfy environmental mitigation requirements as well as reporting and recordkeeping requirements due to the rescission of requirements for transmission and storage sources. Most of the estimated change in labor requirements relative to the baseline come from rescinding the fugitive emissions program for compressor stations in the transmission and storage segment.

The labor information is based on the cost analysis presented in the TSD that supports this rule. The labor estimates include labor associated with company-level activities and activities at field sites. Company-level activities included one-time "up-front" activities such as planning the company's fugitive emissions program and annual requirements such as reporting and recordkeeping. Field-level activities included inspection and repair of leaks.

Table 2-17 presents the incremental change in labor required to comply with the NSPS due to the Policy Review at the facility level in hours per facility per year. The change in estimates for each of the facility types reflect the following changes from the baseline:

- **Compressor Stations** (in transmission and storage segment): removal of quarterly fugitives monitoring requirements.
- **Reciprocating Compressors:** removal of requirement to replace rod-packing every 36 months, or 26,000 hours.
- **Pneumatic Controllers:** removal of requirement to replace high-bleed controllers with low-bleed controllers.

Table 2-17 Changes in Labor Required to Comply at the Impacted Facility Level

	Upfront Labor Estimate (hours per facility)			Annual Labor Estimate (hours per facility per year)		
Facility	**Under the Baseline**	**Under Final Policy Review**	**Incremental Change**	**Under the Baseline**	**Under Final Policy Review**	**Incremental Change**
Compressor Stations						
Transmission	64	0	-64	123.2	0	-123.2
Storage	64	0	-64	227.4	0	-227.4
Compressors						
Reciprocating	1	0	-1	1	0	-1
Pneumatic Controllers	0	0	0	0	0	0

Table 2-18 and Table 2-19 present estimates of the decrease in upfront and annual labor requirements, respectively. The estimates are presented in full-time equivalent (FTE) units in these tables; in this analysis we assume one FTE equals 2,080 hours (the product of 40 hours per week over 52 weeks). Note that reductions in labor requirements increase from 2021 to 2030 as the number of sites that would have been regulated under the NSPS under the baseline accumulates.

Table 2-18 Estimates of the Decrease in Upfront Labor Required (in FTEs) under the Policy Review, 2021–2030

	Compressor Stations					
	Transmission	Storage	Reciprocating Compressors	Pneumatic Controllers	Recordkeeping and Reporting	Total
2021	0.06	1.1	0.07	0	0	1.2
2022	0.06	1.1	0.07	0	0	1.2
2023	0.12	2.2	0.11	0	0	2.4
2024	0.12	2.2	0.11	0	0	2.4
2025	0.12	2.2	0.11	0	0	2.4
2026	0.12	2.2	0.11	0	0	2.4
2027	0.12	2.2	0.15	0	0	2.5
2028	0.12	2.2	0.15	0	0	2.5
2029	0.12	2.2	0.15	0	0	2.5
2030	0.12	2.2	0.15	0	0	2.5

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Estimates may not sum due to independent rounding.

Table 2-19 Estimates of the Decrease in Annual Labor Required (in FTEs) under the Policy Review, 2021–2030

	Compressor Stations					
Year	Transmission	Storage	Reciprocating Compressors	Pneumatic Controllers	Recordkeeping and Reporting	Total
2021	0.8	28	0.26	0	1.7	30
2022	1.0	31	0.29	0	1.8	35
2023	1.1	35	0.33	0	1.9	39
2024	1.2	39	0.37	0	2.0	43
2025	1.3	43	0.40	0	2.1	47
2026	1.4	47	0.44	0	2.3	51
2027	1.5	51	0.48	0	2.4	56
2028	1.7	55	0.51	0	2.5	60
2029	1.8	59	0.55	0	2.6	64
2030	1.9	63	0.58	0	2.7	68

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Estimates may not sum due to independent rounding.

The total incremental reductions in up-front labor requirements among entities affected by the Policy Review are projected to increase from 1.2 FTE in 2021 to 2.5 FTE in 2030. The total incremental reductions in annual labor requirements are projected to increase from about 30 to 68 FTEs from 2021 to 2030.

We note that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy. As stated earlier, this rule is expected to result in little change in oil and natural gas exploration and production and is not expected to result in significant reductions to employment dedicated to these tasks. For the affected oil and natural gas entities, some reductions in compliance-related labor may be expected due to the rescission of requirements for transmission and storage segment under the Policy Review. We did not estimate any potential changes in labor outside of the affected sector. For example, no estimates of labor requirements for manufacturing pollution control equipment, or for producing the materials used in that equipment, are provided as the EPA did not have the information necessary for estimating broader employment impacts.

2.5 Comparison of Benefits and Costs

2.5.1 Comparison of Benefits and Costs

In this section, we present a comparison of the benefits and costs for the Policy Review. Here, we refer to the compliance cost reductions as the "benefits" and the forgone benefits as the "costs" of this action. The net benefits are the benefits (compliance cost reductions) minus the costs (forgone benefits). All benefits, costs, and net benefits shown in this section are presented as the PV of the costs and benefits of the Policy Review from 2021 through 2030 discounted back to 2020 using 7 and 3 discount rates. We also present the associated EAV under each discount rate.

Table 2-20 shows the projected benefits, costs, and net benefits for the Policy Review. Table 2-21 provides a summary of the projected forgone emissions reductions for this action.

Exhibit D

United States Environmental Protection Agency

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

Background Technical Support Document for the

Final New Source Performance Standards

40 CFR Part 60, subpart OOOOa

May, 2016

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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4.0 FUGITIVE EMISSIONS STANDARDS

In the TSD for the proposed rule, monitoring options for reducing fugitive emissions from well sites and compressor stations were analyzed. The monitoring options that were analyzed included optical gas imaging (OGI) and Method 21 at monitoring frequencies of annual, semiannual and quarterly. For Method 21 repair thresholds of 10,000 ppm, 2,500 ppm and 500 ppm were also analyzed for each of the monitoring frequencies. Based on the analysis in the proposed rule TSD, the semiannual OGI monitoring option was selected as BSER for well sites and compressor stations. Comments on the proposed BSER analysis were received during the proposed rule comment period, and the BSER analysis for the OGI option was re-evaluated to take into account these comments. In response to comments, Method 21 was also re-evaluated as an alternative option for fugitive emission monitoring.

4.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as pressure release valves (PRVs), pump seals, valves or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as gas driven pneumatic controllers or gas driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

For the purposes of the analysis and regulatory evaluation of fugitive emissions from components and equipment, the EPA differentiated between the current definition of "equipment" in the rule[32] and the intended definition for the purposes of addressing fugitive emissions. Therefore in the final rule, the EPA have defined a new term, "fugitive emissions component" as the focus of the

[32] The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

requirements for fugitive emissions. The proposed definition for fugitive emissions component is as follows:

> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a gas-driven pneumatic controller or a gas-driven pump, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from sites other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

The EPA received comment that this proposed fugitive emissions component definition was too broad and vague and may include equipment such as separators, pressure vessels, and dehydrators instead of the components (i.e., valves, connectors) on the equipment. The commenters also asserted that the "included but not limited to" description adds uncertainty to what should be included in the collection of fugitive emissions components. Based on these comments, the EPA has revised the definition of fugitive emissions component in the final rule to read:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vesselnot subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

In April of 2014, the EPA published a white paper[33] which summarized the EPA's current understanding of methane and VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities. The white paper also outlined the EPA's understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

4.2 Fugitive Emissions Data and Emissions Factors

4.2.1 Model Plants

For the proposed rule, model plants were developed to estimate fugitive emissions from well sites and compressor stations. Data from the 2016 draft GHG Inventory[34], developed with the most recently published GHGRP reported data, were used to determine the equipment counts for well sites and compressor stations. Component counts per piece of equipment were those used in the GHG Inventory and GHGRP, which were derived the EPA/GRI study and 40 CFR, part 98, subpart W tables, were then used to determine the total number of fugitive components (valves, connectors, OELs, and PRVs) at each of these sites. A description of the data and methodology for determining fugitive emissions for these model plants are discussed in the following sections.

4.2.2 Oil and Gas Production Well Sites

Oil and natural gas production practices and equipment vary from site-to-site. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well pad. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Baseline model plant emissions for the natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from GHG Inventory, derived from GHGRP, EPA/GRI,

[33] U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

[34] The draft 2016 GHG Inventory was the most recent data available at the time of this analysis. The 2016 GHG Inventory was finalized April 15, 2016 with the same data that was used in the public review draft. Therefore, this analysis is consistent with the most recent final GHG Inventory.

and 40 CFR part 98, subpart W tables as described above, and the component oil and natural gas production emission factors from AP-42[35]. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the emissions from the production segment (e.g., oil production well sites and natural gas production well sites) are presented in Table 4-1. The emission factors in Table 4-1 are also used to calculate fugitive emissions from gathering and boosting stations.

Table 4-1. Oil and Gas Production Operations Average TOC Emissions Factors

Component Type	Component Service	Emission Factor[a] (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

4.2.2.1 Proposed Rule Well Site Model Plant

A model plant for natural gas and oil well sites was developed using the average number of wells associated with a well site using data from the DrillingInfo HPDI® database[36]. The analysis, described in the TSD for the proposed rule, determined that the national average of wells per well site was 1.81, and was rounded to 2.0 wells per well site for the model plant fugitive analysis for both natural gas production and oil production well sites.

For the proposed rule, average equipment count per well data from the EPA/GRI document for natural gas production well sites and GHG Inventory for oil production well sites were used to determine the number of production equipment located at a well site. The average equipment count per well for each of the equipment types were multiplied by the average number of wells at a well site (2) and then rounded up to the nearest integer.

The types of production equipment located at a natural gas well site includes: gas wellheads, separators, meters/piping, in-line heaters, and dehydrators. The types of components that are associated

[35] U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)
[36] Drilling Information, Inc. 2011. *DI Desktop.* 2011 Production Information Database.

with this production equipment include: valves, connectors, OELs, and PRVs. Component counts for each of the production equipment items were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report. Fractions of components were rounded up to the nearest integer.

Baseline fugitive emissions for the proposed rule were calculated using the estimated component counts for the natural gas well site and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS[37]. For the proposed rule, the fugitive emissions for the natural gas production well site model plant were determined to be 4.54 tons per year of methane and 1.26 tons per year of VOC.

For oil well sites, data from the GHG Inventory, derived from GHGRP reported data, were used to estimate equipment counts for these sources. The types of oil well site equipment include: oil well heads, separators, headers and heater/treaters. Fugitive emissions components counts for these equipment types were estimated using component count data from Table W-1C of 40 CFR part 98, subpart W.

The estimated baseline fugitive emissions from oil well sites were calculated using the estimated component counts and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. For the proposed rule, the fugitive emissions for the oil well site model plant were determined to be 1.09 tons per year of methane and 0.30 tons per year of VOC.

4.2.2.2 Final Rule Natural Gas Well Site Model Plant

During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016[38] GHG Inventory, and was used to revise the equipment

[37] Memorandum to Bruce Moore. U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking". July 28, 2011.

[38] In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

counts for the natural gas well sites. The average equipment count per well was multiplied by the average number of wells per well site (2) and rounded to the next highest integer. The updated equipment counts per natural gas well site were 2 separators, 3 meters/piping, 1 in-line heaters, and 1 dehydrators per well. In comparison to the model plant in the proposed rule TSD, the only change in equipment counts was for meters/piping which increased from 1 to 3. Average component counts for each piece of equipment were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for natural gas production well sites is presented in Table 4-2.

The baseline fugitive emissions for the natural gas well site model plant were calculated using the revised component counts for the natural gas well site model plant and the oil and natural gas production AP-42 TOC emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the natural gas well site model plant were determined to be 5.50 tons per year of methane and 1.53 tons per year of VOC and are provided in Table 4-3.

4.2.2.3 Final Rule Oil Well Site Model Plant

Comments on the proposed rules stated that methane emissions from oil well site model plants were underestimated. While some oil wells produce very little natural gas (oil wells with a gas-to-oil-ratio less than 300 standard cubic feet of gas per stock barrel of oil), other oil wells produce significant volumes of natural gas (oil wells with a gas-to-oil-ratio greater than 300 standard cubic feet of gas per stock barrel of oil). To address these types of oil wells, two model plants were developed to estimate fugitive emissions from oil well sites. The oil well site model plant developed for the proposed rule was used to define the oils wells with a gas-to-oil ratio less than 300 standard cubic feet of gas per stock barrel of oil (< 300 GOR). During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016[39] GHG Inventory, and was used to revise

[39] In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

the equipment counts for the oil well sites. The equipment count for this model plant consists of 2 oil wellheads, 1 separator, 1 header, and 1 heater/treater. To develop the model plant for oil well sites with a gas-to-oil ratio greater than 300 standard cubic feet of gas per stock barrel of oil (> 300 GOR), three meters/piping were added to the equipment counts included for the < 300 GOR model plant to account for the handling of the natural gas from the well. Component counts for the oil well equipment (wellhead, separator, header, heater/treater) were obtained from Table W-1C of subpart W The component counts for meters/piping were obtained from the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per production equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for oil well site model plants are presented in Table 4-4.

Baseline model plant emissions for the oil well site model plants were calculated using the fugitive emissions component counts and the component oil and natural gas production emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the < 300 GOR model plant were determined to be 1.23 tons per year of methane and 0.33 tons per year of VOC. The fugitive emissions for the > 300 GOR model plant were determined to be 2.75 tons per year of methane and 0.75 tons per year of VOC. A summary of the emissions are provided in Table 4-5.

Table 4-2. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Equipment[a]				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
					Total	138.9	509.4	14.3	6.9
					Rounded Total	139	510	15	7

a. Data Source: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 4-3. Estimated Fugitive Emission Estimate for Natural Gas Well Site Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane[c]	VOC[d]
Valves	139	0.0045	4.196	1.166
Connectors	510	0.0002	0.684	0.190
OELs	15	0.002	0.201	0.056
PRVs	7	0.0088	0.413	0.115
		Total	5.50	1.53

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.
b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
c. Methane emissions calculated using 0.695 weight ratio for Methane/TOC obtained from gas composition memorandum.
d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

Table 4-4. Average Fugitive Emissions Component Count for Oil Well Site Model Plant

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR)[a]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
						Total	29	54	42	0	2
Oil Well Model Plant (> 300 GOR)[b]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
						Total	68	54	186	2	4

a. Oil well (<300 GOR) component counts obtained from Table W-1C pf 40 CFR part 98, subpart W.
b. Oil well (>300 GOR) component counts from 40 CFR Part 98, subpart W, Table W-1C.

Table 4-5. Estimated Fugitive Emission Estimate for Oil Well Site Model Plant

Oil Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane[c]	VOC[d]
Oil Well Model Plant (< 300 GOR)				
Valves	29	0.0045	0.876	0.243
Flanges	54	0.00039	0.185	0.039
Connectors	42	0.0002	0.056	0.016
OELs	0	0.002	0	0
PRVs	2	0.0088	0.118	0.033
		Total	1.23	0.33
Oil Well Model Plant (> 300 GOR)				
Valves	68	0.0045	2.053	0.571
Flanges	54	0.00039	0.185	0.039
Connectors	186	0.0002	0.250	0.069
OELs	2	0.002	0.027	0.007
PRVs	4	0.0088	0.236	0.066
		Total	2.75	0.75

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.
b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
c. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.
d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

4.2.3 Compressor Stations

The proposed rule TSD evaluated fugitive monitoring at three types of compressor stations; gathering and boosting stations, transmission stations and storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas, such as the removal of water or hydrocarbons occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components (e.g., valves, connectors) that may be sources of fugitive emissions associated with these operations.

4.2.3.1 Proposed Rule Compressor Station Model Plant

For the proposed rule TSD, baseline model plant emissions for compressor stations were calculated using the fugitive emissions component counts from the EPA/GRI document and the component oil and natural gas production emission factors from AP-42 for gathering and boosting stations and EPA/GRI emission factors for transmission and storage stations. Annual emissions were calculated assuming 8,760 hours of operation each year. The AP-42 emission factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the new source emissions from the gathering and boosting stations are presented in Table 4-1. In the proposed rule TSD, the fugitive emissions from gathering and boosting stations were estimated to be 35.1 tons per year of methane and 9.77 tons per year of VOC. The model plant fugitive emissions for transmission stations were estimated to be 62.4 tons per year of methane and 1.73 tons per year of VOC, and 164.4 tons per year of methane and 4.55 tons per year of VOC for storage stations.

4.2.3.2 Final Rule Compressor Station Model Plant

Gathering and boosting stations are sites that collect oil and natural gas from well sites and direct them to the natural gas processing plants. These stations have similar production equipment (including separators, meters, piping, compressors, in-line heaters, dehydrators and other equipment) to well sites; however, they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in Chapter 8 of this document. A summary of the fugitive emissions component counts for oil and gas gathering and boosting stations are presented in Table 4-6.

The proposed gathering and boosting model plant did not change from proposal. Therefore, the baseline emissions that are discussed in Section 4.2.3.1 remain the same for the final TSD and are summarized in Table 4-7. The emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

4.2.3.3 Final Rule Natural Gas Transmission and Storage Model Plant

Natural gas transmission and storage stations are facilities that use compressors to move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include production equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compressors operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. The segments include fugitive emissions from components related to inlet and outlet pipelines, meter runs, dehydrators, and other piping located at the compressor building for transmission and storage stations, and injection/withdrawal components associated with the injection/withdrawal well piping at storage stations. This industry segment also includes emissions from compressor related components, but does not include emissions from compressor seals or site blowdown open-ended lines. The blowdown open-ended lines were included in the proposed rule TSD, but were determined, based on comments, to be a vent rather than a fugitive emission source. Therefore in this analysis, emissions from blowdown open-ended lines were removed from the component list and the associated emissions were not included in the total fugitive emissions from transmission and storage stations. For the other components at these facilities, fugitive emissions component counts and methane emission factors were obtained from the EPA/GRI study. A summary of the fugitive emissions component counts, component emission factors and baseline methane and VOC emissions for transmission and storage model plants are presented in Table 4-8. The average fugitive emissions for transmission stations were determined to be 40.4 tons per year of methane and 1.12 tons per year of VOC and 142.4 tons per year of methane and 3.94 tons per year of VOC for storage facilities. These emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Table 4-6. Average Fugitive Emissions Component Count for Gathering and Boosting Station Model Plant

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
Total						906	2,864	83	48
Rounded Total						906	2,864	83	48

a. Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 4-7. Estimated Fugitive Emissions for Gathering and Boosting Station Model Plant

Gathering and Boosting Station Model Plant Component	Model Plant Component Count	Uncontrolled Emission Factor[a] (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Valves	906	0.0045	27.35	7.603
Connectors	2,864	0.0002	3.84	1.068
OELs	83	0.002	1.11	0.310
PRVs	48	0.0088	2.83	0.788
Total			35.1	9.77

a. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
b. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.
c. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

Table 4-8. Estimated Fugitive Emissions for Natural Gas Transmission and Storage Model Plant

Component	Model Plant Component Count[a]	Component Methane Emission Factor[a] (Mscf/year/component)	Methane Emissions[b] (tpy)	VOC Emissions[c] (tpy)
Transmission Facility				
Valve	673	0.867	12.1	0.336
Control Valve	31	8	5.2	0.143
Connectors	3,068	0.147	9.4	0.260
OEL	51	11.2	11.9	0.329
PRV	14	6.2	1.8	0.050
		Total	40.4	1.12
Storage Facility				
Valve	1,868	0.867	33.7	0.933
Connector	5,571	0.147	17.0	0.472
OEL	353	11.2	82.3	2.77
PRV	66	6.2	8.52	0.236
Valve (Inj/With)	30	0.918	0.57	0.016
Connector (Inj/With)	89	0.125	0.23	0.006
OEL (Inj/With)	7	0.237	0.03	0.001
PRV (Inj/With)	1	1.464	0.03	0.001
		Total	142.4	3.94

a. Component counts and methane emission factors for non-compressor related components obtained from EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)
b. Methane emissions calculated by multiplying the model plant component count by the component methane emission factor and converting to tons using the conversion factor 0.02082 tons methane/Mscf methane.
c. VOC emissions calculated using 0.0277 weight ratio for VOC/methane obtained from Gas Composition memorandum.

4.3 Control Techniques

4.3.1 Potential Control Techniques

The use of OGI and Method 21 to monitor and reduce fugitive emissions from well sites and compressor stations was evaluated in the TSD for the proposed rule. Based on this analysis, it was determined that semiannual monitoring using OGI was BSER for both well sites and compressor stations. The EPA received numerous comments on this BSER determination and re-evaluated the OGI option using updated information received during the comment period. The re-evaluation for the final rule is provided in the following sections.

4.3.2 Fugitive Emissions Detection and Repair with OGI

4.3.2.1 Description

The reduction of fugitive emissions from well sites and compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities) involves the development of a fugitive emissions monitoring plan. Under this option, the final rule states that monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company defined area. The monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

In order to estimate the cost of implementation of a monitoring and repair plan, the EPA needed to estimate the cost of repair, which is based on the number of components found to have fugitive emissions. Since OGI visualizes gaseous emissions using active or passive infrared imaging, the OGI the operator would not be able to determine the exact concentration or emission rate of the fugitive emissions; however, all visualized fugitive emissions would be required to be repaired. If a fugitive emissions component cannot be immediately repaired during the monitoring survey, the operator must repair or replace the component as soon as practicable, but no later than 30 days after detection of the fugitive emissions. For this resurvey, the operator may use OGI, Method 21 or the alternative screening procedures specified in section 8.3.3 of Method 21 to confirm that the component is no longer emitting fugitive emissions. When OGI is used for the resurvey, no visible emissions indicate that the fugitive emissions component has been repaired. When Method 21 is used for the resurvey, no detectable emissions (e.g., a concentration of less than 500 ppm above background) indicate that the fugitive emissions component has been repaired.

4.3.2.2 Emission Reduction Potential

Information in the white paper related to the potential emission reductions from OGI monitoring and repair varied from 40 to 99 percent. The data from these studies are based on the gathering of individual OGI surveys at various oil and natural gas segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found during the OGI survey and assumptions made by the authors. However, these studies in the white paper did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program. A report was found after the publication of the white paper from the Colorado Air Quality Control Commission[40] which estimated 40 percent reduction for annual OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy (≥ 6 to ≤ 12 tpy), 60 percent reduction for quarterly OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy (> 12 to ≤ 50 tpy), and 80 percent reduction for monthly OGI monitoring at well production tank batteries with an uncontrolled VOC emission greater than 50 tpy (> 50 tpy).

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on the information in the studies and EPA's engineering judgement, the potential emission reduction percentages for the proposed rule were estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies[41] were calculated using the data from the EPA Protocol document. For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500

[40] Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9).* February 7, 2014.
[41] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program, April 25, 2016.

ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF[42] using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semi-annual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emissions reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emissions reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.[43]

4.3.2.3 Cost Impacts

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

[42] ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016.
[43] See Emission Reduction Comparison - Well Sites.xls and Emission Reduction Comparison – Compressor Stations.xls in the docket for more information.

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $57.80 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $231.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,468.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for annual monitoring was estimated to be $925 semiannual monitoring was estimated to be $1,850 and quarterly monitoring $3,699.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $58 for compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities). For companies that own and operate well sites, the cost notification of compliance status was estimated to be $58 per well site for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.
- Cost of a Method 21 Monitoring Device of $10,800.
- Costs for implementing a fugitive emission monitoring plan for a company defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:
- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $925 per monitoring event. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $42 per monitoring event.
- The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well site and $2,300 for a compressor station.[44]
- Annual repair costs were estimated to be $299 per monitoring event for well sites, $3,436 per monitoring event for gathering and boosting stations, $3,361 per monitoring event for transmission stations, and $6,946 per monitoring event for storage facilities. These costs were estimated assuming that 1.18 percent of the components are found to leak[45] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.

[44] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.
[45] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (e.g., pumps LL, valve LL, agitators LL). There is no information

- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $58 per hour. This assumes the company is able to perform the resurvey without retaining contractors. The capital costs include the cost of Method 21 instrumentation (estimated to be $10,800[46]). For compressor stations, the cost to resurvey repaired components was estimated to be $2.00 per component.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, notification of initial compliance status, and purchase of a Method 21 instrumentation. The total capital cost of these activities was calculated to be $17,620 per company defined areas for semiannual monitoring and $19,470 per company define areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[47], the capital cost per well site was estimated to be $759 for annual monitoring, $801 for semiannual monitoring and $885 for quarterly monitoring. For compressor stations (gathering and boosting stations, transmission stations and storage facilities) the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation was calculated to be $16,407 per facility. For gathering and boosting stations, this capital cost was assumed to be shared with other gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated 7 gathering and boosting stations, and the capital cost of each of these stations was estimated to be $2,393.

For all oil and natural gas segments, the annual cost includes; subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and

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on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[46] Average of subsequent monitoring costs in Table 13 from the Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180

[47] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, semiannual and quarterly OGI surveys. The OGI monitoring cost memorandum[48] present the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocates the annual cost among the pollutants (multi-pollutant approach) that a given technology reduced (i.e., GHG (in the form of limiting methane emissions) and VOC). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (i.e., gathering and boosting, transmission and storage). Table 4-9, 4-10 and 4-11 presents a summary of the cost of control for methane and VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly, respectively) based on the single-pollutant method. Tables 4-12, 4-13 and 4-14 present a summary of the capital and annual costs, and the cost of control for methane and VOC using the multi-pollutant method (i.e., 50 percent of the cost attributed to methane and 50 percent of the cost attributed to VOC).

[48] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA, Evaluation of Cost methodologies for OGI Monitoring, April 6, 2016.

4.3.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors[49] and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO_X). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X.

[49] AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. https://www3.epa.gov/otaq/ap42.htm#highway

Table 4-9. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option – Single Pollutant[50]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Well Site[d]	2.20	0.61	$759	$1,318	$809	$600	$2,158	$368	$1,324
Oil Well Site (GOR < 300)[d]	0.49	0.13	$759	$1,318	$1,204	$2,670	$9,953	$2,438	$9,089
Oil Well Site (GOR > 300 GOR)[d]	1.10	0.30	$759	$1,318	$1,063	$1,198	$4,380	$967	$3,533
Well Site Program Weighted Average[h]						**$1,224**	**$4,464**	**$993**	**$3,619**
Gathering & Boosting Station[e]	14.1	3.91	$2,393	$7,777	$7,777	$553	$1,990	$553	$1,990
Transmission Station[f]	16.2	0.45	$16,407	$10,117	$10,117	$626	$22,626	$626	$22,626
Storage Facility[g]	57.0	1.58	$16,407	$13,798	$13,798	$242	$8,751	$242	$8,751
Compressor Stations Program Weighted Average[h]						**$541**	**$3,098**	**$541**	**$3,098**

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[50] As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Table 4-10. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option – Single Pollutant[51]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	3.3	0.917	$801	$2,285	$1,521	$693	$2,494	$461	$1,660
Oil Well Sites (GOR < 300) [d]	0.74	0.199	$801	$2,285	$2,114	$3,085	$11,503	$2,854	$10,639
Oil Well Site (GOR > 300 GOR)[d]	1.65	0.451	$801	$2,285	$1,903	$1,385	$5,062	$1,153	$4,215
Well Site Program Weighted Average[h]						**$1,415**	**$5,160**	**$1,183**	**$4,314**
Gathering & Boosting Station[e]	21.1	5.86	$2,393	$13,534	$13,534	$642	$2,309	$642	$2,309
Transmission Station[f]	24.2	0.67	$16,407	$15,868	$15,868	$655	$23,659	$655	$23,659
Storage Facility[g]	85.5	2.37	$16,407	$23,230	$23,230	$272	$9,822	$272	$9,822
Compressor Stations Program Weighted Average[h]						**$625**	**$3,480**	**$625**	**$3,480**

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $13,120 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $20,482 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[51] *Ibid*.

Table 4-11. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option -Single-Pollutant[52]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	4.4	1.222	$885	$4,220	$3,201	$960	$3,453	$728	$2,619
Oil Well Sites (GOR < 300) [d]	0.99	0.265	$885	$4,220	$3,991	$4,272	$15,929	$4,041	$15,064
Oil Well Site (GOR > 300 GOR)[d]	2.20	0.602	$885	$4,220	$3,710	$1,918	$7,010	$1,686	$6,163
Well Site Program Weighted Average[h]						**$1,960**	**$7,145**	**$1,728**	**$6,299**
Gathering & Boosting Station[e]	28.1	7.81	$2,393	$25,049	$25,049	$891	$3,205	$891	$3,205
Transmission Station[f]	32.3	0.89	$16,407	$27,369	$27,369	$847	$30,606	$847	$30,606
Storage Facility[g]	114.0	3.15	$16,407	$42,093	$42,093	$369	$13,348	$369	$13,348
Compressor Stations Program Weighted Average[h]						**$864**	**$4,732**	**$864**	**$4,732**

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.
b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $24,622 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $39,345 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.

Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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[52] *Ibid*.

Table 4-12. Summary of the Model Plant Cost of Control for the Annual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	2.20	0.61	$759	$1,318	$809	$300	$1,079	$184	$662
Oil Well Sites (GOR < 300) [d]	0.49	0.13	$759	$1,318	$1,204	$1,335	$4,977	$1,219	$4,545
Oil Well Site (GOR > 300 GOR)[d]	1.10	0.30	$759	$1,318	$1,063	$599	$2,190	$483	$1,767
Well Site Program Weighted Average[h]						**$612**	**$2,232**	**$496**	**$1,810**
Gathering & Boosting Station[e]	14.1	3.91	$2,393	$7,777	$7,777	$277	$995	$277	$995
Transmission Station[f]	16.2	0.45	$16,407	$10,117	$10,117	$313	$11,313	$313	$11,313
Storage Facility[g]	57.0	1.58	$16,407	$13,798	$13,798	$121	$4,375	$121	$4,375
Compressor Stations Program Weighted Average[h]						**$271**	**$1,549**	**$271**	**$1,549**

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $16,696 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $1,191 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $7,376 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $7,369 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $11,050 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 4-13. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	3.3	0.917	$801	$2,285	$1,521	$347	$1,247	$231	$830
Oil Well Sites (GOR < 300) [d]	0.74	0.199	$801	$2,285	$2,114	$1,543	$5,752	$1,427	$5,319
Oil Well Site (GOR > 300 GOR)[d]	1.65	0.451	$801	$2,285	$1,903	$693	$2,531	$577	$2,108
Well Site Program Weighted Average[h]						**$708**	**$2,580**	**$592**	**$2,157**
Gathering & Boosting Station[e]	21.1	5.86	$2,393	$13,534	$13,534	$321	$1,155	$321	$1,155
Transmission Station[f]	24.2	0.67	$16,407	$15,868	$15,868	$327	$11,829	$327	$11,829
Storage Facility[g]	85.5	2.37	$16,407	$23,230	$23,230	$136	$4,911	$136	$4,911
Compressor Stations Program Weighted Average[h]						**$312**	**$1,740**	**$312**	**$1,740**

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $17,620 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $13,120 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $20,482 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 4-14. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Sites[d]	4.40	1.222	$885	$4,220	$3,201	$480	$1,726	$364	$1,310
Oil Well Sites (GOR < 300) [d]	0.99	0.265	$885	$4,220	$3,991	$2,136	$7,964	$2,020	$7,532
Oil Well Sites (GOR > 300 GOR)[d]	2.20	0.602	$885	$4,220	$3,710	$959	$3,505	$843	$3,081
Well Site Program Weighted Average[h]						**$980**	**$3,572**	**$864**	**$3,150**
Gathering & Boosting Station[e]	28.1	7.8	$2,393	$25,049	$25,049	$445	$1,603	$445	$1,603
Transmission Station[f]	32.3	0.9	$16,407	$27,369	$27,369	$424	$15,303	$424	$15,303
Storage Facility[g]	114.0	3.2	$16,407	$42,093	$42,093	$185	$6,674	$185	$6,674
Compressor Stations Program Weighted Average[h]						**$432**	**$2,366**	**$432**	**$2,366**

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.
b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $24,622 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $39,345 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

4.4 Regulatory Options

Monitoring of fugitive emissions was evaluated using OGI and Method 21 in the TSD for the proposed rule. For OGI, monitoring frequencies of annual, semiannual and quarterly were evaluated for well sites and compressor stations. Annual, semiannual and quartering monitoring was also evaluated for Method 21 at three different leak definitions; 500 ppm, 2,500 ppm and 10,000 ppm. Based on the results of these evaluations, semiannual monitoring using OGI was selected as BSER for well sites and compressor stations.

For this analysis, the OGI monitoring options were updated for the final rule using information received since proposal for the proposed rule. The OGI monitoring options include;

- Regulatory Option 1 – The implementation of an annual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 2 - The implementation of a semiannual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 3 - The implementation of a quarterly OGI fugitive emissions monitoring and repair program.

4.4.1 OGI Monitoring Options

As noted above, the EPA calculated a weighted average cost of control for well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 4-15.

Table 4-15. Summary of the Cost of Control for the OGI Monitoring Options[53]

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Well Sites								
1 - Annual	$1,224	$4,464	$612	$2,232	$993	$3,619	$496	$1,810
2 - Semiannual	$1,415	$5,160	$708	$2,580	$1,183	$4,314	$592	$2,157
3 - Quarterly	$1,960	$7,145	$980	$3,572	$1,728	$6,299	$864	$3,150
Compressor Stations								
1 - Annual	$504	$2,225	$252	$1,112	$272	$1,201	$136	$601
2 - Semiannual	$580	$2,562	$290	$1,281	$396	$1,749	$198	$875
3 - Quarterly	$802	$3,540	$401	$1,770	$618	$2,728	$309	$1,364

4.4.2 EPA Method 21 as an Alternative to OGI Monitoring

4.4.2.1 Description

As an alternative to OGI monitoring, the EPA evaluated allowing the use of Method 21 to detect fugitive emissions from the collection of the fugitive emissions components at well sites and compressor stations to determine if the emissions reductions were equal to or greater than the emissions reductions achieved using OGI monitoring. As with OGI monitoring, emissions reductions vary based on the frequency of the monitoring of the components as well as the repair threshold. Based on comments received on the proposed rule, the EPA evaluated repair thresholds of 500 ppm and 10,000 for Method 21fugitive emissions monitoring.

4.4.2.2 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair

[53] *Ibid*.

components, the percentage of new leaks and the percentage of leaks that were repaired but have reoccurred. The EPA Protocol does not provide these data for oil and natural gas production; only for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refineries. The refinery emissions data are provided in non-methane organic compound (NMOC) units, which would require assumed TOC and methane weight fractions to determine the TOC emission factors, whereas the SOCMI emissions data is already based on TOC. The assumed TOC and methane weight fractions would add another level of uncertainty to the emission reduction percentage calculations if the refinery data were used. Therefore, we determined that using the SOCMI data would provide the best estimate of potential fugitive emission reduction percentages for a typical Method 21 monitoring program, and would be comparable to the potential fugitive emission reductions for oil and gas production, if the other parameters were available for this segment. The potential emission reduction from the implementation of a Method 21 program was calculated using this SOCMI data. Table 4-16 provides a summary of the parameters used to calculate the monitoring cycles. An example of the methodology is provided in Chapter 5.3.2 of the EPA Protocol document. The SOCMI data in the EPA Protocol document only included occurrence rates for monthly and quarterly monitoring. To calculate annual and semiannual occurrence rates, a logarithmic equation was derived from the data points. Initial leak frequencies were calculated using the EPA Protocol average leak rate equations for 500 and 10,000 ppm gas valves (see Table 5-4) and the average SOCMI emission factor for gas valves of 0.00597 kilograms per hour per source (see Table 2-1) and solving for leak fraction. The initial leak frequencies can also extrapolated using the lines in Figure 5-1 in the EPA Protocol document. The average leak fraction equation and calculated initial leak frequency are provided in Table 4-16.

Using the parameters in Table 4-16, the estimated emission reductions were calculated using the monitoring cycle approach in the EPA Protocol document. The leak frequency after monitoring reached steady state on the sixth monitoring cycle and the percent reduction was calculated. The results of the emission reductions are presented in Table 4-17.

Table 4-16. Parameters and Assumptions Used to Calculate Monitoring Cycles

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	13.53%	7.49%
Average Leak Rate Equation	ALR = 0.044*LF + 0.000017	ALR = 0.078*LF + 0.00013

Table 4-17. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair

Monitoring Frequency	Fugitive Percent Reduction		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Annual	42	68	40
Semiannual	55	75	60
Quarterly	67	83	80

As noted in Table 4-17 above, in all cases the percent reduction for the 500 parts per million Method 21 alternative is equal to or greater than the estimated OGI monitoring and repair percent reduction. The percent reduction for the 10,000 parts per million leak threshold was only greater than the OGI option for annual monitoring. Based on the estimated OGI monitoring model plant emission reductions (see Tables 4-9 through 4-14), Table 4-18 summarizes the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 parts per million leak thresholds. For annual monitoring, both the Method 21 leak thresholds had higher emission reductions then the OGI monitoring option. Only the 500 parts per million leak threshold had emission reductions that were equal to or greater than the OGI monitoring option for semiannual and quarterly monitoring.

Table 4-18. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gas Well Sites	2.20	0.61	2.32	0.65	3.75	1.04
Oil Well Sites (GOR < 300)	0.49	0.13	0.52	0.14	0.84	0.23
Oil Well Sites (GOR > 300)	1.10	0.30	1.16	0.32	1.88	0.51
Gathering & Boosting	14.1	3.91	14.8	4.12	24.0	6.67
Transmission	16.2	0.45	17.0	0.47	27.6	0.76
Storage	57.0	1.58	60.1	1.66	97.3	2.69
Semiannual Monitoring						
Gas Well Sites	3.30	0.92	3.01	0.84	4.14	1.15
Oil Well Sites (GOR < 300)	0.74	0.20	0.68	0.18	0.93	0.25
Oil Well Sites (GOR > 300)	1.65	0.45	1.51	0.41	2.07	0.57
Gathering & Boosting	21.1	5.86	19.3	5.35	26.5	7.37
Transmission	24.2	0.67	22.1	0.61	30.5	0.84
Storage	85.5	2.37	78.1	2.16	107.4	2.97
Quarterly Monitoring						
Gas Well Sites	4.40	1.22	3.70	1.03	4.53	1.26
Oil Well Sites (GOR < 300)	0.99	0.26	0.83	0.22	1.02	0.27
Oil Well Sites (GOR > 300)	2.20	0.60	1.85	0.51	2.27	0.62
Gathering & Boosting	28.1	7.81	23.7	6.58	29.0	8.06
Transmission	32.3	0.89	27.2	0.75	33.3	0.92
Storage	114.0	3.15	96.0	2.66	117.5	3.25

a. Assumes baseline emissions shown in Tables 4-5 and 4-8 and percent reduction shown in Table 4-21.

9.0 NATIONWIDE IMPACTS FOR FUGITIVE EMISSIONS STANDARDS

9.1 Nationwide Emissions from New Sources

9.1.1 Overview of Approach

Similar to the approach used to calculate emissions from well site and compressor station model plants, nationwide emissions were calculated by using the model plant emissions that were calculated for the oil and natural well sites and compressor stations. These model plant emissions were used for estimating the baseline emissions and emission reductions for the new sources.

9.1.2 Activity Data

Data from oil and natural gas technical documents and inventories were used to estimate the number of new sources for each of the oil and natural gas segments. Information from the DrillingInfo HPDI® database and GHG Inventory were used to estimate the number of new well sites, gathering and boosting stations, and transmission and storage facilities in 2012. A summary of the steps used to estimate the new sources for each of the oil and gas segments is presented in the following sections.

9.1.2.1 Well Sites

The DrillingInfo database provided the information on the number of oil and natural gas wells completed or recompleted in the 2012 in the U.S. The total number of new natural gas well completions, both conventional and fractured was determined to be 8,456. From this number of wells, the EPA subtracted wells that were assumed to be covered by state leak regulations as of the effective date of the revised NSPS. Based on our research, four states have recently enacted leak regulations; Colorado, Ohio, Wyoming and Utah. Below is a brief discussion of these state regulations:

- Colorado: Effective on April 14, 2014, requires well production facilities and natural gas compression station owners/operators to inspect components for leaks using an approved instrument monitoring method (AIMM). This LDAR program began as early as January 1, 2015 with inspection frequency varying based on the amount of fugitive VOC emissions identified (i.e., 0-6 tpy - one-time, 6-12 tpy -annually, 12-50 tpy -quarterly, or >50 tpy -monthly). Monitoring inspections of well production facility and compressor station components must be conducted using Method 21, an infra-red camera, or other Division approved instrument based monitoring devices or methods. In addition, monthly audio, visual, and olfactory inspections must be conducted to identify leaks. When OGI is used for leak detection, a leak is defined as any detectable emissions that are not associated with normal equipment operation (e.g. pneumatic device actuation)[119]. For compressor station facilities constructed prior to May 1, 2014, a leak is defined as any concentration of hydrocarbon above 2,000 ppm when Method 21 is used to conduct monitoring inspections. For well sites and compressor stations that were constructed on or after May 1, 2014, a leaks is defined as any concentration of hydrocarbon above 500 ppm when Method 21 is used.

- Ohio: On May 19, 2014 Ohio EPA approved two types of oil and gas well-site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing general permits for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT HH). Operators are required to develop and implement a site-specific LDAR program for ancillary equipment (e.g., vent, compressor, PRD, flange, etc.) that requires monitoring using a FLIR camera or Method 21. Quarterly monitoring is required for the first year and varies after that depending on performance.[120] Ohio has also proposed a package of general permits that have been designed around a natural gas compressor station that has the potential to leak greater than 10 tons per year of VOC. The general permit requirements include quarterly monitoring of ancillary equipment, including each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel using either an OGI or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.

- Utah: On June 5, 2014, Utah Department of Environmental Quality approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014. This GAO requires LDAR for equipment (e.g., valves, pumps, etc.) at least annually, and initial quarterly surveying of sources with projected annual throughput of crude oil and condensate combined that is greater than 25,000 barrels. The monitoring can be performed using Method 21 (leak definition of 500 ppm), a tunable diode laser absorption spectroscopy or an IR camera.[121]

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119 Colorado regulations available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.
120 Ohio regulations available at http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits.
121 Utah regulations are available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

- Wyoming: On June 30, 2015, Wyoming Department of environmental Quality issued regulations for existing (as of January 1, 2014) PAD and single-well oil and gas production facilities that are located in the Upper Green River Basin. The rule regulates fugitive emissions from PAD and single-well facilities or sources, and compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOC and requires owner/operators to develop and implement an LDAR protocol by January 1, 2017. Fugitive emissions monitoring can be conducted using a combination of Method 21, OGI, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule - at least one quarterly evaluation must be done using Method 21, OGI, or other instrument based technology. The rule requires quarterly monitoring of control equipment, systems, and devices (e.g. reboiler overhead condensers, storage tanks, vent lines, valves, connectors, etc.).[122]

9.1.3 Emission Estimates

The nationwide emissions were calculated using the model plant data and the estimated number of new and modified sources for each of the segments. The nationwide emission estimates for the total number of oil and natural gas production well sites, gathering and boosting stations, and transmission and storage facilities incrementally affected by the fugitive emission requirements in the NSPS for are summarized in Table 9-1. The summary includes baseline emissions for each of these segments for projected years 2020 and 2025.

Table 9-1. Nationwide Baseline Emissions for Sources Subject to NSPS Monitoring and Repair Plans in 2020 and 2025

Oil and Gas Segment	Number of Sources Subject to NSPS[a]	Methane Emissions (tpy)	VOC Emissions (tpy)
Projected Year 2020			
Natural Gas Well Sites	16,819	92,425	25,692
Oil Well Sites (GOR < 300)	32,392	39,989	10,726
Oil Well Sites (GOR > 300)	44,367	122,013	33,382
Gathering & Boosting Stations	480	16,868	4,689
Transmission Stations	20	808	22
Storage Stations	25	3,561	99

[122] Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.

Oil and Gas Segment	Number of Sources Subject to NSPS[a]	Methane Emissions (tpy)	VOC Emissions (tpy)
Projected Year 2025			
Natural Gas Well Sites	34,487	189,515	52,680
Oil Well Sites (GOR < 300)	66,173	81,693	21,912
Oil Well Sites (GOR > 300)	90,636	249,256	68,196
Gathering & Boosting Stations	960	33,737	9,378
Transmission Stations	40	1,616	45
Storage Stations	50	7,122	197

a. Affected facilities in 2020 include new facilities in 2016 through 2020 which are assumed to still be operating in 2020. Affected facilities in 2025 includes new affected facilities in 2016 through 2025 which are assumed to still be operating in 2025.

According to our analysis, 20.87 percent of the total number of new natural gas well completions, both conventional and fractured, were covered by leak regulations in these four states. Therefore the number of new natural gas wells covered by federal regulations was estimated to be 6,691. Assuming an average of two natural gas wells per well site, the number of new well sites in 2012 was estimated to be 3,346. Projections from the NEMS data were used to estimate the total number of new natural gas completions, both conventional and hydraulically fractured in the years 2020 and 2025. The percentage of wells covered by state leak regulations, and the 2 natural gas wells per well site assumptions were applied to these totals to estimate the number of new natural gas production well sites. Our projected activity for year 2020 was developed to reflect the total number of affected facilities in 2020 which is the accumulation of newly affected facilities from 2016 through and including 2020. Likewise, our projected year 2025 reflects total accumulated newly affected facilities from 2016 through and including 2025. These activity estimates assume all newly affected facilities continue to be operating in the projected years. The number of natural gas well sites was estimated to be 16,819 well sites in 2020 and 34,487 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 30 percent of the total natural gas well sites based on a sensitivity analysis of the well site data.

For oil wells, the same approach used for natural gas wells was used to estimate the number of new oil wells in the U.S. The number of new oil well completions in 2012, both conventional and hydraulically fractured, was determined to be 35,404. It was assumed that 8.81 percent of these oil wells are covered by state regulations in 2012 based on information in the HPDI database, which includes: Colorado, Ohio, Wyoming and Utah. Therefore 32,285 new oil wells were not covered by state leak regulations in 2012. Assuming an average of two oil production wells per well site, the number of new oil production well sites was determined to be 16,142 in 2012. Projections from the NEMS data were used to estimate the total number of new oil well completions in the years 2020 and 2025. The percentage of wells covered by State leak regulations, and the two oil wells per well site assumptions was applied to these totals to estimate the number of new oil well production sites. Because the requirements have impacts annually, our projected activity for years 2020 and 2025 were developed to reflect the facilities newly affected by the rule from 2016 through 2020 and 2016 through 2025, respectively, and assumed to still be in operation in the analysis years. The number of oil well sites were estimated to be 76,759 well sites in 2020 and 156,809 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 43 percent of the total oil well sites based on a sensitivity analysis of the well site data. Oil well sites with a gas-to-oil ratio of greater than 300 were assumed to account for 57.8 percent of the total oil well sites based on data from the HPDI database as summarized in Table 9-1.

9.1.3.1 Gathering and Boosting Stations

The number of new gathering and boosting stations was estimated using the current number of gathering compressors estimated in the GHG Inventory. The total number of small and large gathering compressors was listed as 36,066 in the inventory. The EPA/GRI document does not include a separate list of individual compressors for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the total number of compressors in the GHG Inventory, the number of gathering and boosting stations was estimated to be 8,015. To estimate the number of new gathering and boosting stations, the EPA used an annual growth rate of 1.2 percent, which is based on the gas well CAGR for new gas wells divided by the average wells per well site. This provided an estimate of 96 new gathering and boosting stations each year that would be affected sources under the proposed NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

9.1.3.2 Transmission and Storage Facilities

The number of new transmission and storage facilities was estimated by reviewing the annual number of facilities from the year 1990 to 2013 estimated in the GHG Inventory published in 2015 and determining the rate of change in the number of these facilities over this period. The average change for the last 10 years was reviewed and the annual number of new transmission stations was determined to be 4 and the annual number of storage facilities was determined to be 5. The values were used to estimate the number of affected sources under the NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

9.1.4 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to the regulatory options which were selected as a viable options for reducing fugitive emissions from fugitive emissions components located at production well sites and compressor stations.

9.1.4.1 Primary Environmental Impacts of Regulatory Options

Based on the discussion above, the EPA reconsidered Regulatory Options 1 and 2 for well sites and Regulatory Options 1, 2 and 3 for compressor stations. A summary of the options are provided below;

- Regulatory Option 1. Require the implementation of a fugitive emissions monitoring and repair program which includes annual monitoring of fugitive emissions components using OGI.
- Regulatory Option 2. Require the implementation of a fugitive emissions monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using OGI.
- Regulatory Option 3. Require the implementation of a fugitive emissions monitoring and repair program which includes quarterly monitoring of fugitive emissions components using OGI.

The number of oil and natural gas well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to the regulatory options listed above were estimated using data from the HPDI database. In 2020, which include all new and modified sources since 2016, it was estimated that there would be 76,759 oil well sites, 16,819 gas well sites, 480 gathering and boosting stations, 20 transmission stations, and 25 storage facilities subject to these options. In 2025, which include all new and modified sources since 2016, it was estimated that there would be 156,809 oil well sites, 34,487 gas well sites, 960 gathering and boosting stations, 40 transmission stations, and 50 storage facilities subject to these options.

It was estimated that OGI monitoring and repair can achieve an overall 40 percent VOC and methane reduction for annual monitoring, 60 percent VOC and methane reduction for semiannual monitoring, and 80 percent VOC and methane reduction for quarterly monitoring over the life span of the facility. These percent reduction values were estimated based on information from the EPA white paper and an analysis by the Colorado Air Quality Control Commission as described previously. Nationwide emission reductions were estimated by applying this 40, 60 and 80 percent VOC and methane reduction to the uncontrolled baseline emissions for well sites and compressor stations. In considering the three frequency options, the EPA considered the implementation issues with respect to the monitoring and repair plan and the EPA determined that, based on input from industry and regulatory agencies, that the program frequency should be consistent across the segments in the oil and natural gas source category. Therefore, nationwide impacts were estimated for these options as presented in Tables 9-2, 9-3 and 9-4.

9.1.4.2 Cost Impacts

<u>OGI Monitoring and Repair Plans (Options 1, 2 and 3)</u>

Regulatory Option 1 include annual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-2) include the costs for having a contractor perform the annual OGI survey, activities planning, repair costs, resurvey of repaired components using a Method 21 device, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of an annual OGI monitoring and repair program at well sites was calculated to be 127 thousand standard cubic feet per year (Mscf/yr) for a natural gas production well site, 64 Mscf/yr for an oil well site with a GOR > 300, and 29 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas saved was calculated to be 815 Mscf/yr for gathering and boosting stations, 836 Mscf/yr for transmission stations, and 2,950 Mscf/yr for storage facilities.[123]

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue

[123] Natural gas savings calculated using the CH_4 reductions and assuming a methane to natural gas volume ration of 82.9% for upstream facilities (well sites, gathering & boosting) and a methane to natural gas volume ratio of 92.8% for downstream facilities (transmission, storage).

from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA. Table 9-2 also summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 1.

Regulatory Option 2 include semiannual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-3) include the costs for having a contractor perform the semiannual OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas savings from the implementation of a semiannual OGI monitoring and repair program were calculated to be 191 Mscf/yr for a natural gas production well site, 96 Mscf/yr for an oil production well site with a GOR > 300, and 43 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas savings were calculated to be 1,222 Mscf/yr for gathering and boosting stations, 1,255 Mscf/yr for transmission stations, and 4,424 Mscf/yr for storage facilities.[124] Table 9-3 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 2.

Regulatory Option 3 for well sites and compressor stations include quarterly monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-4) include the costs for having a contractor perform the quarterly OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of a quarterly OGI monitoring and repair

[124] Ibid.

program at well sites was calculated to be 255 Mscf/yr for a natural gas production well site, 127 Mscf/yr for an oil well site with a GOR > 300, and 57 Mscf/yr for an oil production well site with a GOR < 300. The potential natural gas savings at compressor stations were calculated to be 1,629 Mscf/yr for gathering and boosting stations, 1,673 Mscf/yr for transmission stations, and 5,899 Mscf/yr for storage facilities.[125] Table 9-4 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 3.

9.1.4.3 Low Producing Natural Gas and Oil Wells

For the proposed rule, the EPA evaluated an alternative nationwide impact scenario that accounts for well sites that produce relatively little crude oil and/or natural gas. The EPA had proposed that low producing wells not be subject to fugitive emissions monitoring provisions. While there were several criteria for defining a low-producing well, the EPA believed the definition of a "stripper well" in Internal Revenue Services (IRS) regulations, was consistent with the type of well which would be considered low-producing under that scenario. Under the IRS regulations, a stripper well property “means, with respect to any calendar year, any property with respect to which the amount determined by dividing—(i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by (ii) the number of such wells, is 15 barrel equivalents or less". [126] This proposal was based on our belief at the time that low production wells have inherently low emissions from well completions and that many are owned and operated by small businesses. The EPA was concerned about the burden of the well completion requirement on small businesses, in particular if there is little emission reduction to be achieved.

However, based on information provided in the comments for the proposed rule, the EPA determined that fugitive emissions from low production wells may be comparable to fugitive emissions from other production wells. The low production well sites have the same type of equipment (e.g., separators, storage vessels) and components (e.g., valves, flanges, connectors) as production well sites with production greater than 15 boe per day. This indicates that the component counts for low production well sites are similar to that of non-low production well sites, and hence the potential fugitive emissions from both types of well sites are comparable. The comments on the proposed rule stated that many of these well sites are developed for leasing purposes and are typically unmanned and not visited as often as

[125] Ibid.
[126] 26 U.S.C. 613A(c)(6)(E).

other well sites. This may potentially allow fugitive emissions to go unnoticed longer. No data were provided in the comments on the proposed rule that shows low production well sites have lower GHG (principally as methane) or VOC emissions than normal production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In addition, discussions with the industry indicated that well site fugitive emissions are not based on production, but rather on the number of equipment and components. Therefore, the EPA believes that the emissions from low production and non-low production well sites are likely comparable and are included as affected sources for fugitive emissions.

Table 9-2. Nationwide Emission and Cost Analysis for Regulatory Option 1 – Annual OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility ($)	Annual Cost Per Facility ($)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million $/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	$1,318	$809	36,970	10,277	$22.2	$13.6
Oil Well Sites (GOR < 300)	32,392	$1,318	$1,204	15,996	4,290	$42.7	$38.9
Oil Well Sites (GOR > 300)	44,367	$1,318	$1,063	48,805	13,353	$58.5	$47.2
Well Sites Total	**93,578**	**NA**	**NA**	**101,771**	**27,920**	**$123.4**	**$99.7**
Gathering & Boosting	480	$7,777	$4,518	6,747	1,876	$3.7	$2.2
Transmission	20	$10,117	$6,372	323	9	$0.2	$0.1
Storage	25	$13,798	$590	1,424	39	$0.3	$0.01
Compressor Stations Total	**525**	**NA**	**NA**	**8,494**	**1,924**	**$4.2**	**$2.3**
Projected Year 2025							
Gas Well Sites	34,487	$1,318	$809	75,806	21,072	$45.5	$27.9
Oil Well Sites (GOR < 300)	66,173	$1,318	$1,204	32,677	8,765	$87.2	$79.7
Oil Well Sites (GOR > 300)	90,636	$1,318	$1,063	99,702	27,278	$119.5	$96.4
Well Sites Total	**191,296**	**NA**	**NA**	**208,185**	**57,115**	**$252.2**	**$204**
Gathering & Boosting	960	$7,777	$4,518	13,495	3,751	$7.5	$4.3
Transmission	40	$10,117	$6,372	646	18	$0.4	$0.3
Storage	50	$13,798	$590	2,849	79	$0.7	$0.02
Compressor Stations Total	**1,050**	**NA**	**NA**	**16,990**	**3,848**	**$8.6**	**$4.6**

Table 9-3. Nationwide Emission and Cost Analysis for Regulatory Option 2 – Semiannual OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility ($)	Annual Cost Per Facility ($)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million $/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	$2,285	$1,521	55,455	15,415	$38.4	$25.6
Oil Well Sites (GOR < 300)	32,392	$2,285	$2,114	23,993	6,436	$74.0	$68.5
Oil Well Sites (GOR > 300)	44,367	$2,285	$1,903	73,208	20,029	$101.4	$84.4
Well Sites Total	**93,578**	**NA**	**NA**	**152,656**	**41,880**	**$213.8**	**$178.5**
Gathering & Boosting	480	$13,534	$8,646	10,121	2,813	$6.5	$4.2
Transmission	20	$15,868	$10,250	485	13	$0.3	$0.2
Storage	25	$23,230	$3,418	2,137	59	$0.6	$0.1
Compressor Stations Total	**525**	**NA**	**NA**	**12,743**	**2,885**	**$7.4**	**$4.5**
Projected Year 2025							
Gas Well Sites	34,487	$2,285	$1,521	113,709	31,608	$78.8	$52.5
Oil Well Sites (GOR < 300)	66,173	$2,285	$2,114	49,016	13,147	$151.2	$139.9
Oil Well Sites (GOR > 300)	90,636	$2,285	$1,903	149,554	40,917	$207.1	$172.5
Well Sites Total	**191,296**	**NA**	**NA**	**312,279**	**85,672**	**$437.1**	**$364.9**
Gathering & Boosting	960	$13,534	$8,646	20,242	5,627	$13.0	$8.3
Transmission	40	$15,868	$10,250	969	27	$0.6	$0.4
Storage	50	$23,230	$3,418	4,273	118	$1.2	$0.2
Compressor Stations Total	**1,050**	**NA**	**NA**	**25,484**	**5,772**	**$14.8**	**$8.9**

Table 9-4. Nationwide Emission and Cost Analysis for Regulatory Option 3 – Quarterly OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility ($)		Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million $/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	$4,220	$3,201	73,940	20,553	$70.9	$53.8
Oil Well Sites (GOR < 300)	32,392	$4,220	$3,991	31,991	8,581	$136.7	$129.3
Oil Well Sites (GOR > 300)	44,367	$4,220	$3,710	97,610	26,706	$187.2	$164.6
Well Sites Total	**93,578**	**NA**	**NA**	**203,541**	**55,840**	**$394.8**	**$347.7**
Gathering & Boosting	480	$25,049	$18,532	13,495	3,751	$12.0	$8.9
Transmission	20	$27,369	$19,879	646	18	$0.5	$0.4
Storage	25	$42,093	$15,678	2,849	79	$1.1	$0.4
Compressor Stations Total	**525**	**NA**	**NA**	**16,990**	**3,848**	**$13.6**	**$9.7**
Projected Year 2025							
Gas Well Sites	34,487	$4,220	$3,201	151,612	42,144	$145.5	$110.4
Oil Well Sites (GOR < 300)	66,173	$4,220	$3,991	65,354	17,530	$279.2	$264.0
Oil Well Sites (GOR > 300)	90,636	$4,220	$3,710	199,405	54,557	$382.4	$336.2
Well Sites Total	**191,296**	**NA**	**NA**	**416,371**	**114,231**	**$807.1**	**$710.6**
Gathering & Boosting	960	$25,049	$18,532	26,989	7,502	$24.0	$17.8
Transmission	40	$27,369	$19,879	1,293	36	$1.1	$0.8
Storage	50	$42,093	$15,678	5,698	158	$2.1	$0.8
Compressor Stations Total	**1,050**	**NA**	**NA**	**33,980**	**7,696**	**$27.2**	**$19.4**

15.0 COMPARISON OF TOTAL COST IMPACTS TO OVERALL INDUSTRY CAPITAL EXPENDITURES AND RECEIPTS

In order to provide another perspective on the reasonableness of the estimated cost of control as determined in our evaluation of BSER for the final standards as presented in Volume 1 of this TSD, we analyzed the total cost of the rule for each type of affected facility (as presented in Volume 2 of this TSD) under two additional approaches using industry economic data.

First, we compared the total nationwide capitals costs that would be incurred for each type of affected facility to comply with the final standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the final standards to the level of new capital expenditures that the industry is incurring in the absence of the final standards. Capital expenditure data for relevant NAICS codes covered by the rule were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey[135]. For the capital expenditures analysis, we determined the estimated nationwide capital costs estimated to be incurred by each type of affected facility to comply with the final standards[136], then divided the nationwide capital costs by the new capital expenditures (census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. For example, we used the total estimated capital cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total capital expenditures the NAICs codes that correspond to oil and natural gas production segment. Table 15-1 below summarizes the capital expenditure data used for our analysis.

For fugitive emissions standards at well sites and compressor stations, there are no actual capital cost identified in the TSD. Instead, for the purposes of this portion of the analysis, we used the first-year corporate-based costs for these standards.

[135] Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2013, Table 4a. See http://www.census.gov/econ/aces/xls/2013/full_report.html

[136] The total capital cost estimate is based on the number of estimated affected facilities within the year and the capital cost per facility, however, the capital expenditure may not actually be incurred in that year.

In the second approach, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us determine whether the annualized costs appears reasonable as a percentage of the revenues being generated by the industry. The annualized cost, as calculated for the rule, includes capital cost annualized using a seven percent discount rate plus any annually incurred cost for implementation of a control technology. We included, where applicable, the cost savings realized from recovered natural gas. The annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census[137]. For the annual revenues analysis, we determined the estimated nationwide annualize costs incurred by each type of affected facility to comply with the final standards[138], then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. For example, we used the total annual cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total receipts for the NAICs codes that correspond to oil and natural gas production segment. Table 15-2 below summarizes the revenue data used for our analysis.

For the capital expenditures, the production segment was represented with the NAICS codes 21111 " Crude Petroleum and Natural Gas Extraction" and 213111 and 213112 " Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 4862 "Pipeline transportation of natural gas". For revenue, the production segment was represented with the NAICS codes 21111 " Crude Petroleum and Natural Gas Extraction" and 213112 " Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 486210 "Pipeline transportation of natural gas". Although there is not a one-to-one correspondence between NAICS codes and the

[137] Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Employment Size for the United States, All Industries: 2012. Release date: 6/22/2015. 2012 County Business Patterns and 2012 Economic Census. For information on confidentiality protection, sampling error, and nonsampling error, see http://www.census.gov/econ/susb/methodology.html. For definitions of estimated receipts and other definitions, see http://www.census.gov/econ/susb/definitions.html.

[138] The estimated nationwide annualized costs were determined based on the estimated number of affected facilities in that year, however, these annualized costs are not necessarily incurred within that same year.

industry segments we used in the development of the analysis, we believe there is enough similarity to draw accurate conclusions.

Because we are aware the different owners or operators are generally involved in the different industry segments, we conducted the analysis at the affected facility level to ensure proper characterization of the impact. We also conducted the analysis for all sources in the production segment and in the transmission and storage segment. Table 15-3 summarizes the result of our analysis. In all cases we found that the rule impacts in comparison to either capital expenditures or revenues represent a fraction of one percent.

Table 15-1. NAICS-Based Capital Expenditure Data

Capital Expenditures Data (millions $, current$)			
Oil and Natural Gas Segment	**NAICS code**	**NAICS DESCRIPTION**	**Total New Expenditures**
Production	2111	Crude Petroleum and Natural Gas Extraction	$158,911
	213111 213112	Support activities for oil and gas operations	$19,966
Transmission and Storage	4862	Pipeline transportation of natural gas	$12,891

Table 15-2. NAICS-Based Revenue Data

Revenue Data (millions $, 2012$)				
Oil and Natural Gas Segment	**NAICS CODE**	**NAICS DESCRIPTION**	**ESTIMATED RECEIPTS ($1,000)**	**ESTIMATED RECEIPTS (millions 2012$)**
Production	211111	Crude Petroleum and Natural Gas Extraction	$276,076,578	$276,077
	213112	Support Activities for Oil and Gas Operations	$90,645,566	$90,646
Processing	211112	Natural Gas Liquid Extraction	$49,236,136	$49,236
Transmission and Storage	486210	Pipeline Transportation of Natural Gas	$26,587,330	$26,587

Table 15-3. Comparison of Final NSPS OOOOa Nationwide Cost in 2025, by Affected Facility Cost to Industry Wide Capital Expenditures and Revenues

Oil and Natural Gas Segment/ Affected Facility	Number of Sources Subject to NSPS	Total Nationwide Capital Costs	Total Nationwide Annual Cost	Nationwide Capital Cost/ Capital Expenditures	Nationwide Annual Cost/Receipts
	Units	(million 2012$)	(million $)	(%)	(%)
Production					
Hydraulically Fractured Oil Well Completions and Recompletions	21,000	160	130	0.09	0.04
Pneumatic Pumps	8,000	43	6.1	0.02	0.00
Fugitives - Well Sites	190,000	150	365	0.09	0.10
Total Production Segment	219,000	353	501	0.20	0.14
Transmission and Storage					
Compressors					
- Reciprocating	320	2	1	0.02	0.00
- Centrifugal	10	$1.1	1	0.06	0.04
Pneumatic Controllers	960	0	0	0.00	0.00
Fugitives - Compressor Stations	1,100	4	27	0.03	0.10
Total Transmission and Storage Segment	2,400	7	29	0.11	0.14

Source : All cost information is from the "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa" available in the docket. For Hydraulically Fractured Oil Well Completions and Recompletions from Table 8-4, for Gas Driven Pumps from Table 11-4, for Fugitives - Well sites from Table 9-3, for Compressors, Reciprocating from Table 12-3, for Centrifugal from Table 12-4, for Pneumatic controllers from- Table 10-3, and for Fugitives - Compressor Stations from Table 9-4. The analysis results are rounded to two significant digits for this presentation. Capital costs reflect capital costs associated with affected facilities in 2025, including expenditures made prior to 2025.

Exhibit E

Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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EPA-452/R-16-002, May 2016

Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

6 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

6.1 Introduction

This section includes three sets of analyses for the final NSPS:

- Energy Markets Impacts
- Final Regulatory Flexibility Analysis
- Employment Impacts

6.2 Energy Markets Impacts Analysis

We use the National Energy Modeling System (NEMS) to estimate the impacts of the final NSPS on U.S. energy markets. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas.

A brief conceptual discussion about our energy markets impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and presenting results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain in production at the producer level for a given cost. For example, the analysis for the rule shows that performing reduced emissions completions on hydraulically-fractured oil wells would account for about 36 percent of the natural gas captured by emissions controls in 2020 and about 23 percent of captured natural gas in 2025. The fugitive emissions program at well sites is expected to account for about 62 percent of the natural gas captured by emissions controls in 2020 and about 75 percent of captured natural gas in 2025. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production.

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

6.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of the U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy (DOE). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. DOE first developed NEMS in the 1980s, and the model has undergone frequent updates and significant expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

The EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at the website: http://www.eia.gov/forecasts/aeo/.

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel *et al.* 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next module after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2040. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2015.[76] The RIA baseline is consistent with that of the Annual Energy Outlook 2015, which is used extensively in Section 2 in the Industry Profile.

6.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the final rule, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore and Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2014). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern findings and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the NSPS. We are able to target additional expenditures for environmental controls required by the NSPS on new exploratory and developmental oil and gas production activities. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the rule.

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[76] Assumptions for the 2015 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/>.

While the oil production simulated by the OGSM is sent to the refining module (the Liquid Fuels Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas is transported through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

6.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Regulatory costs associated with reduced emission completions for hydraulically fractured oil well completions are added to the drilling and completion costs of oil wells in the OGSM. Other regulatory costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The additional expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells or natural gas wells. We base the per well cost estimates on the engineering costs. Because we model natural gas recovery, we do not include revenues from additional product recovery in these costs. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

In general, the cost of capital in the model will implicitly capture potential barriers to obtaining additional capital financing for the industry on average. However, the model may not fully capture heterogeneity in the cost of capital across the industry, and therefore, may not fully capture distributional impacts across the industry as a result of firm specific characterisitics that cause them to have varying access to additional capital. An additional caveat to this analysis is that the modeling does not attempt to represent potential constraints on the supply of specific capital equipment, which may or may not be binding in practice.

Table 6-1 shows the incremental compliance that accrue to new drilling projects as a result of producers having to comply with the NSPS, across sources anticipated in 2020 and

2025. We estimate those costs as a function of new wells anticipated to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify whether costs will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells.

We divide the estimated compliance costs for the given emissions point by the appropriate number of expected new crude oil and natural gas wells in the year of analysis. The result yields an approximation of per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Hydraulically fractured oil well completions and fugitives at oil and natural gas well sites differ slightly from this approach. Drilling and completion costs of new hydraulically fractured oil wells are incremented by the weighted average of the cost of performing a REC with completion combustion and completion combustion alone. The resulting cost is itself weighted by the proportion of new hydraulically fractured oil wells estimated to be affected by the regulation. Meanwhile, assuming there is an average of two wells per wells site (see TSD for more details), new oil and gas wells face an increased annual cost of one-half of implementing the well site fugitive emission requirements.

Table 6-1 Per Well Costs for Environmental Controls Entered into NEMS (2012$)

Emissions Sources/Points	Wells Applied To in NEMS	Annualized Cost per Unit (2012$)	Per Well Costs Applied in NEMS (2012$)	Natural Gas Recovery per Unit (Mcf)	Per Well Natural Gas Recovery Applied in NEMS (Mcf)
Well Completions					
Hydraulically Fractured Oil Well Completions	New Hydraulically Fractured Oil Wells	Varies[a]	$4,590	0	0
Fugitive Emissions					
Oil Production Well Sites	New Oil Wells	$2,285	$905	191[c]	38
Natural Gas Production Well Sites	New Gas Wells	$2,285	$1,101	73	18
Gathering and Boosting Stations	New Gas Wells	$25,050	$284	1,629	18
Transmission Stations	New Gas Wells	$27,370	$13	1,673	1
Storage Facilities	New Gas Wells	$42,093	$25	5,899	3
Reciprocating Compressors					
Transmission Stations	New Gas Wells	$1,748	$3	1,122	2
Storage Facilities	New Gas Wells	$2,077	$4	1,130	2
Centrifugal Compressors					
Storage Facilities	New Gas Wells	$114,146	$0	0	0
Pneumatic Controllers -					
Transmission and Storage Stations	New Gas Wells	$25	$0	144	2
Pneumatic Pumps					
Well Sites	New Wells	$774	$15	0	0
Reporting and Recordkeeping	New Wells	$6,200,000[b]	$154	0	0

[a] Since compliance costs vary across hydraulically fractured oil well completions, this table uses the weighted average costs by completion cost type.
[b] Reporting and recordkeeping costs are assumed to be equally allocated across all new wells.
[c] Natural gas recovery at oil well sites is the weighted average of the recovery expected from oil well sites and oil well (associated gas) sites. See TSD for detailed description of these model well sites.

6.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A result of controlling methane and VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right in an increment consistent with the technically achievable emissions transferred into the production stream as a result of the final NSPS. We enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 6-1).

6.2.3 Energy Markets Impacts

We estimate impacts to drilling activity, price and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas. In each of these estimates, we present estimates for the baseline years of 2020 and 2025 and predicted results for 2020 and 2025 under the final rule. We also present impacts over the 2020 to 2025 period. For context, we provide estimates of production activities in 2012. With the exception of examining crude oil and natural gas trade, we focus the analysis on onshore oil and natural gas production activities in the continental (lower 48) U.S. We do this because offshore production is not affected by the NSPS and the bulk of the rule's impacts are expected to be in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 6-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.

Table 6-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Successful Wells Drilled							
Natural Gas	10,490	10,501	10,481	12,200	12,145	65,896	65,785
Crude Oil	28,496	27,455	27,463	29,244	29,231	168,768	168,736
Total	**38,986**	**37,956**	**37,944**	**41,444**	**41,376**	**234,664**	**234,521**
% Change in Successful Wells Drilled from Baseline							
Natural Gas			0.19%		-0.45%		-0.17%
Crude Oil			0.03%		-0.04%		-0.02%
Total			**0.03%**		**-0.16%**		**-0.06%**

Results show that the final NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, with very slight increases both oil and natural gas wells, relative to the baseline. Meanwhile, drilling of both natural gas and crude oil wells decreases slightly in 2025, relative to the baseline. The small increase in drilling in 2020 is somewhat counter-intuitive as production costs have been increased under the proposed NSPS. However, given NEMS is a dynamic, multi-period model, it is important to examine changes over multiple periods. Crude oil drilling over the 2020 to 2025 period decreases overall but by about 30 wells total, or about 0.02 percent, relative to the baseline. Natural gas drilling, over the same period remains declines by about 110 wells total, or about 0.17 percent, relative to the baseline.

Table 6-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS.

Table 6-3 Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Domestic Production							
Natural Gas (trillion cubic feet)	22.158	26.544	26.537	28.172	28.163	164.130	164.086
Crude Oil (million bbls/day)	4.597	8.031	8.031	8.027	8.028	48.084	48.086
% Change in Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)							
Natural Gas			-0.03%		-0.03%		-0.03%
Crude Oil			0.00%		0.01%		0.00%

As indicated by the estimated change in the new well drilling activities, the analysis shows that the proposed NSPS will have a relatively small impact on onshore natural gas and crude oil production in the lower 48 states. Crude oil production remains essentially unchanged in 2020 and 2025 (with changes around or less than 0.01 percent in both years), relative to the baseline. While slightly increasing over the time horizon, the overall change in crude oil production is less than 0.01 percent, relative to the baseline. Natural gas production is estimated to decrease slightly during the 2020-25 period, by around 0.03 percent, relative to the baseline.

Note this analysis estimates very little change in domestic natural gas production, despite some environmental controls anticipated in response to the rule capture natural gas that would otherwise be emitted (about 16 bcf in 2020 and 27 bcf in 2025). NEMS models the adjustment of energy markets to the new slightly more costly natural gas and crude oil productive activities. At the new post-rule equilibrium, producers implementing emissions controls are still anticipated to capture and sell the captured natural gas, and this natural gas might offset other production, but not so much as to make overall production increase from the baseline projections.

Table 6-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 6-4 Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012$)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Lower 48 Average Wellhead Price							
Natural Gas (2012$ per Mcf)	2.566	4.428	4.441	5.184	5.190	4.880	4.890
Crude Oil (2012$ per barrel)	94.835	73.920	73.918	85.219	85.218	79.530	79.527
% Change in Lower 48 Average Wellhead Price from Baseline							
Natural Gas			0.29%		0.12%		0.20%
Crude Oil			0.00%		0.00%		-0.01%

Wellhead crude oil prices for onshore lower 48 production are not estimated to change meaningfully in 2020 or 2025, or over the 2020-25 period, relative to the baseline. The production-weighted average price for wellhead crude oil over the 2020 to 2025 period is not estimated to change more than 0.01 percent, relative to the baseline. Meanwhile, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly in response to the rule in 2020 by about 0.29 percent and by about 0.12 percent in 2025, relative to the baseline. The production-weighted average price for wellhead natural gas over the 2020 to 2025 period is estimated to increase by around 0.2 percent, relative to the baseline.

Table 6-5 Net Imports of Natural Gas and Crude Oil

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	**Baseline**	**NSPS**	**Baseline**	**NSPS**	**Baseline**	**NSPS**
Net Imports							
Natural Gas (trillion cubic feet)	1.519	-2.557	-2.554	-3.502	-3.498	-18.959	-18.939
Crude Oil (million barrels/day)	8.459	5.513	5.513	6.073	6.072	5.857	5.857
% Change in Net Imports							
Natural Gas			0.12%		0.11%		0.11%
Crude Oil			0.00%		-0.02%		0.00%

Meanwhile, as shown in Table 6-5, net imports of natural gas are estimated to increase slightly in 2020 and 2025 relative to the baseline (by about 0.12 percent and 0.11 percent, respectively) relative to the baseline. Net imports of natural gas are also expected to increase by about 0.11 percent across the 2020 to 2025 period under the rule. Crude oil imports are not estimated to change in 2020 and to decrease slightly in 2025 by about 0.02 percent relative to the baseline. Over the 2020 to 2025 period, net imports of crude oil are not estimated to change in response to the rule.

6.3 Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104121), provides that whenever an agency publishes a final rule after a general notice of proposed rulemaking is made, it must prepare and make available a final regulatory flexibility analysis (FRFA), unless it certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. §605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. A FRFA describes the economic impact of the rule on small entities and any significant alternatives to the rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 604 of the RFA, the EPA prepared a final regulatory flexibility

Exhibit F

Attachment 5

Declaration of Dr. David R. Lyon, Environmental Defense Fund

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

DECLARATION OF DR. DAVID R. LYON

I, David R. Lyon, declare as follows:

1. I am a Scientist at the Environmental Defense Fund ("EDF").

2. I earned a PhD in Environmental Dynamics from the University of Arkansas, where I wrote my dissertation on *Quantifying, Assessing, and Mitigating Methane Emissions from Super-emitters in the Oil and Gas Supply Chain*. Prior to earning my PhD, I worked in the Arkansas Department of Environmental Quality, where I analyzed emissions data and managed an air pollution emissions inventory program. My curriculum vitae is attached as Exhibit A.

3. I joined EDF in 2012. At EDF, my work focuses on identifying and analyzing emissions from the oil and natural gas industry. I design, plan, execute, and analyze scientific studies to measure methane emissions from the natural gas supply chain. This has included helping to lead a multi-institutional effort to measure facility-specific and regional methane emissions in the Barnett Shale along with several studies characterizing super-emitters—disproportionally large emitters that are often not fully captured in emissions inventories. I have authored or coauthored numerous

peer-reviewed journal articles describing the results of these studies and have served as an expert reviewer of the Petroleum Systems and Natural Gas Systems portions of EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks.

EPA's Leak Detection and Repair Requirements in the 2016 Rule.

4. The Administrator has signed a notice to stay for 90 days the leak detection and repair requirements ("LDAR") in EPA's final rule: Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed and Modified Sources, 81 Fed. Reg. 35,824 ("2016 Rule"). EPA has also sent a proposal to the Office of Management and Budget to extend the stay of these provisions.

5. These leak detection and repair standards require affected sources, which include new and modified well sites and compressor stations, to monitor for leaks using instrument-based technologies like infrared cameras and to fix any leaks within 30 days of the monitoring survey. The 2016 Rule requires that well sites undertake these LDAR surveys twice a year and that compressor stations complete such surveys quarterly. The deadline for affected facilities to complete their initial surveys was June 3, 2017,[1] one

[1] The regulations require sources to comply by June 3, 2017 or within 60 days of the commencement of production, whichever is later. Accordingly, some more recently drilled wells that have not yet commenced production may have later compliance deadlines. These sources are discussed more fully in later portions of this declaration.

year after the final rule was signed several days after the Administrator signed EPA's 90-day stay notice.

EPA's Stay Will Allow Thousands of Oil and Natural Gas Facilities To Forego Inspection and Repair of Leaks.

6. The 2016 Rule applies to facilities "constructed, modified or reconstructed" after September 18, 2015—the date of EPA's proposed rule. 81 Fed. Reg. 35824, 35844 (June 3, 2016). As described above, EPA's LDAR standards apply to new well sites and compressor stations, *id.* at 35826, sources that have commenced construction after September 18, 2015. The standards also apply to modified well sites and compressor stations. The 2016 Rule defines particular circumstances that constitute a modification at each of these facilities. For well sites, these include when a well at an existing site is fractured or re-fractured, an operation that is designed to increase production of natural gas. 40 CFR 60.5365a(i)(3). For compressor stations, the 2016 Rule defines modifications to include the addition of a compressor at an existing station. 40 CFR 60.5365a(j).

7. To analyze the number of affected well sites that, but for EPA's stay, would have been required to perform LDAR surveys and reduce their emissions, I used Drillinginfo, a proprietary database that compiles information from state oil and gas commissions concerning a wide range of drilling and production-related information.

8. Drillinginfo includes information on the "spud date" for wells, or the date on which drilling commenced. The database also includes information on well "completion dates," or the most recent date on which a well was cleared of flowback gas associated with hydraulic fracturing or re-fracturing. Using the database, I isolated wells with a spud date after September 18, 2015, which would be "new" for purposes of the 2016 Rule's LDAR requirements. Separately, I identified wells with a spud date on or before September 18, 2015 but a completion date after September 18, 2015. This distinct category of sources category includes both older, re-fractured wells and new wells with their initial fracture delayed to after September 18, 2015, which would be "modified" for purposes of the 2016 Rule's LDAR requirements.

9. I further narrowed this dataset in several ways to conservatively approximate the number of wells that would have had to perform LDAR absent EPA's stay. First, I removed offshore wells and wells with a producing status that is either abandoned, shut in, cancelled or plugged and abandoned. This yielded a total of 18,231 affected wells (9,262 new wells and 8,969 modified wells that were spudded before September 18, 2015 but completed after that date to avoid any double counting).

10. Second, I isolated, excluded, and separately characterized wells that had not yet reported any oil or gas production. Of the 18,231 total wells, 3,778

wells, or about 20 percent, are not yet producing (2,998 new wells and 790 modified wells). These wells are affected facilities under the NSPS that will have to perform LDAR surveys by June 3, 2017 or within 60 days of first production, whichever is later. While lack of production data is often simply due to a lag in reporting, some of these wells may not yet have commenced production. In that case, non-producing wells may not have had to perform surveys by June 3, but would nonetheless need to complete an initial survey within 60 days of first production. Because that date may fall within the 90-day stay and, at minimum, would likely fall within EPA's anticipated extended stay, I have retained these sources as a separate category, but have not attributed any emission reductions to these wells.

11. Third, a number of states have adopted LDAR standards under their own state authorities. EPA recognized this in its final Regulatory Impact Analysis and, because of these preexisting state-level requirements, determined that the 2016 Rule would not have costs for new and modified sources in Colorado, Wyoming, Utah, and Ohio.[2] Along with these states, California has subsequently adopted LDAR requirements and Pennsylvania provides an exemption from air permitting requirements for well sites if the

[2] EPA, *Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources* at 3-10 (EPA-452/R-16-002, May 2016) ("RIA").

operator voluntarily performs annual LDAR. Accordingly, I have isolated, excluded, and separately characterized producing wells in these states. The dataset includes 3,667 affected wells in such states (2,767 new wells and 900 modified wells). Separating these sources results in a conservative estimate of foregone emission reductions, because EPA's LDAR requirements are more protective than some state standards and so would likely deliver incremental benefits for some of these sources if not for the stay. This analysis is also particularly conservative given that the Pennsylvania provisions addressing LDAR at well sites are not mandatory.

12. After making these conservative adjustments, there are 11,883 producing wells in states without preexisting LDAR requirements that will not now be required to inspect and repair their leaks because of EPA's stay. As discussed above, however, many of the additional wells that have been excluded from this count in the full dataset would nonetheless likely experience emission benefits due to EPA's LDAR standards.

13. My estimate of wells that will not have to comply with the 2016 Rule's LDAR requirements because of EPA's stay is also conservative because it does not include all recently-completed wells or wells that will be completed during the stay period. In particular, the Drillinginfo data, though the most recently available, often does not include activity from the last several

months. For instance, the most recently available data for Texas, the state with the largest number of newly-drilled and modified wells, is April of 2017. And for other states, like Pennsylvania, the data is current only to December of 2016. As of June 2, 2017, Baker Hughes reports that there are 916 active drilling rigs drilling new wells in the United States—wells that likely are not captured by the Drillinginfo database and now will be affected by the stay.[3] Similarly, Drillinginfo reports more than 16,000 new oil and gas wells have been permitted in 2017, less than 30% of which have already been drilled. More broadly, every day a stay is in place, additional, new wells are being drilled and completed, compounding the number of sources that may not be required to perform leak detection and repair because of EPA's stay. For instance, in the Regulatory Impact Analysis for the 2016 Rule, EPA estimated that 22,355 additional new oil wells and 15,773 additional natural gas wells would be drilled in the lower 48 states in 2017 alone.[4]

14. Finally, I assumed that few sources would choose to comply with LDAR standards in advance of the compliance deadline and as a result, that any such pre-compliance would not meaningfully affect my emissions estimates.

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[3] Baker Hughes, Inc., *Rig Count Overview & Summary Count* (June 2, 2017), http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsoverview.
[4] RIA at 2-28.

This is a reasonable assumption because operators have identified a full one-year phase-in as necessary, in their view, to enable compliance.[5] It is likewise reasonable because EPA provided assurance in an April 18th letter from the Administrator that the agency would be suspending the LDAR requirements.

15. Table 1 summarizes my analysis of wells affected by EPA's stay of the 2016 Rule LDAR requirements. Table 2 contains production information for affected wells. Figures 1 and 2 include maps of affected wells both nationally and in states without state regulations requiring some form of LDAR.

Table 1: Summary of Affected Well Sites

	New Wells	Modified Wells	All Wells	Producing Wells
Nationwide	9,262	8,969	18,231	14,451
States with no LDAR Requirements	6,495	8,069	14,564	11,883

[5] *See, e.g.*, EPA, Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 4-482 (May 2016), *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7632 (Comment of American Petroleum Institute requesting one-year plus 60 day phase in "to allow operators time to purchase monitoring devices, conduct training, and establish protocols.").

Table 2: Summary of Oil and Gas Production*

	New Well Production	Modified Well Production	All Wells Production	Low-Producing Wells
Oil [bbl]	304,204,004	389,426,822	693,630,826	13,272,131
Gas [Mcf]	1,755,731,292	2,559,954,063	4,315,685,355	54,929,176

*Estimated oil and gas production data only include months since the completion or recompletion that occurred after September 18, 2015.

Figure 1: Map of Total Affected Well Sources

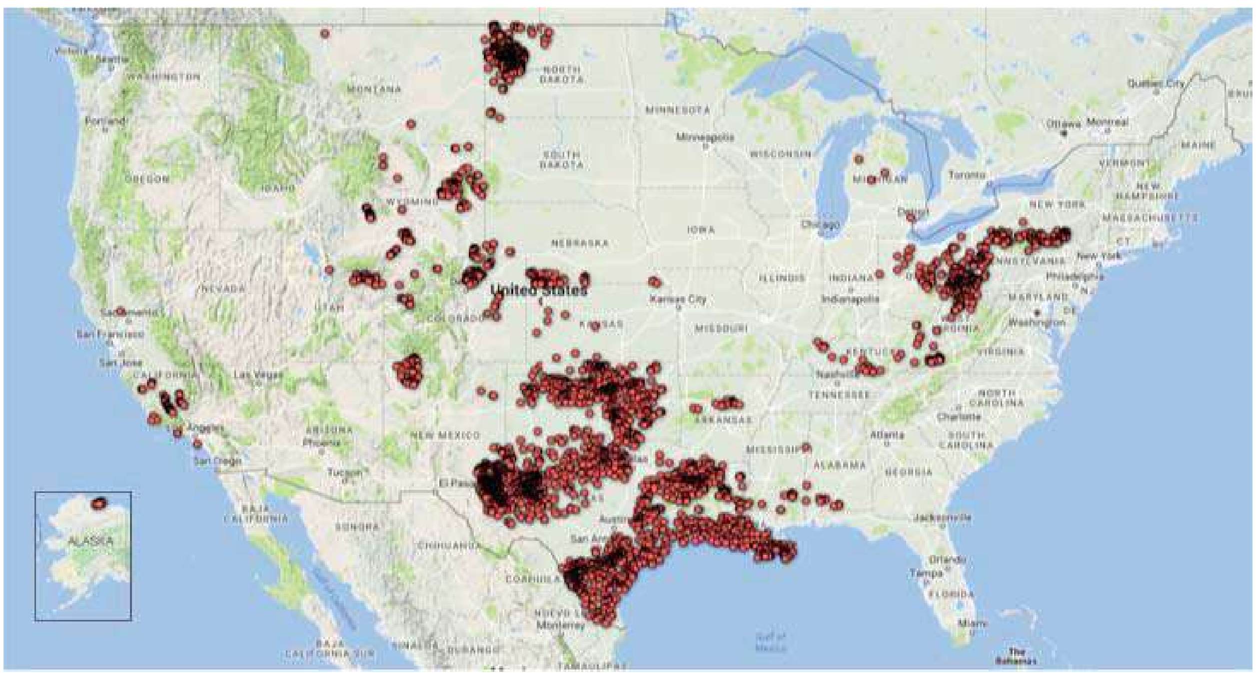
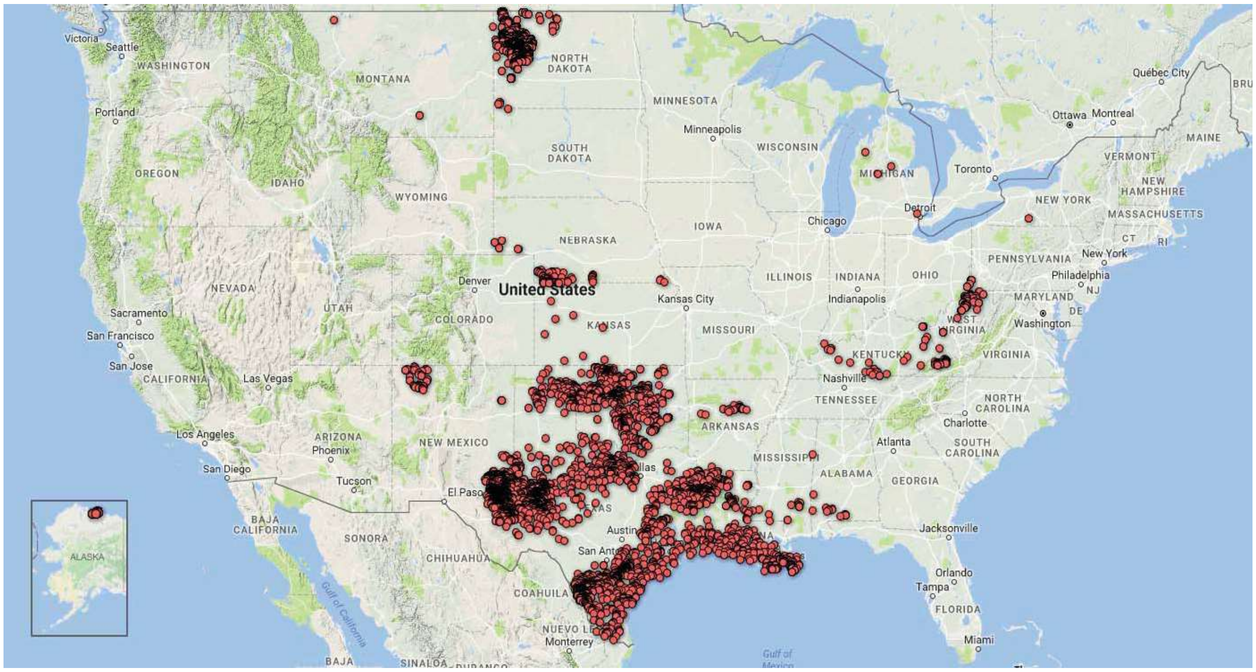


Figure 2: Map of Affected Well Sources in States Without LDAR Requirements



16. Drillinginfo does not compile information on compressor stations. To estimate the impacts of the stay on these sources, I used EPA's projections in the Technical Support Document for the final rule, Table 9-1, which estimate 480 additional affected compressor stations by 2020. Assuming this estimate reflects a constant rate of new development, I estimated that 96 new gathering and boosting compressor stations would be subject to EPA's now suspended LDAR requirements. I undertook a similar approach to analyzing likely new transmission and storage compressor stations,

estimating that 4 transmission and 5 storage facilities were constructed since September 18, 2015.[6]

EPA's Stay of the Leak Detection and Repair Standards Will Result in Additional Emissions of Harmful Methane, Volatile Organic Compounds, and Hazardous Air Pollutants from Well Sites.

17. A stay of the 2016 Rule's LDAR provisions will result in additional emissions of methane, volatile organic compounds ("VOCs"), and hazardous air pollutant emissions that would otherwise be remediated by these requirements. Methane is a powerful short-term climate forcer with over 80 times the global warming potential of carbon dioxide on a mass basis over the first 20-years after it is emitted. VOCs react with nitrogen oxides to form ground-level ozone, or smog, which can cause respiratory disease and premature death. Other hazardous air pollutants emitted by oil and gas sources include benzene, a known human carcinogen.

18. To estimate emissions that will now continue unabated because of EPA's stay, I have used information in EPA's Technical Support Document on average methane and VOC leak emissions[7] from oil and natural gas well sites; the reductions EPA estimates from performing semiannual LDAR at

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[6] EPA, Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa, Table 9-1 (May 2016), *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631.

[7] *Id.* at Tables 4-3, 4-5. EPA's well site model plants assume a two wellhead pad. Oil well emissions are based on EPA's estimates for well sites with a gas-to-oil ratio of less than 300 standard cubic feet of gas per stock barrel of oil.

well sites; and the number of affected well sites from my analysis of the Drillinginfo database, analyzed above. Emissions estimates of hazardous air pollutants ("HAPs") from producing wells are estimated using EPA's HAP-to-methane ratio for equipment leaks from oil and gas well sites.[8]

19. My analysis assumes, consistent with EPA's technical analysis, that semiannual monitoring will reduce annual emissions by 60% and quarterly monitoring will result in an 80% annual emission reduction.[9] While these inspections would not all occur within the initial, 90-day stay period, EPA has indicated that it will extend the stay beyond 90 days, and so these estimates provide a reasonable approximation of the near-term impacts of EPA's stays.

20. To provide a conservative, lower-bound estimate of the emissions impacts of the 90-day stay, I have assumed a constant rate of reduction over the year and reduced the annual emission reduction benefits accordingly. This assumption understates, perhaps significantly, the true foregone benefits of the initial survey, which was required to take place by June 3, 2017. This is because field surveys have often found that equipment leak emissions are highest shortly after the completion of a new facility. For example, third-

[8] *Id.* at Table 14-1.
[9] *See id.* at Tables 4-10, 4-11.

party data from Jonah Energy shows reductions of nearly 60% for the initial survey[10]—substantially greater than the estimated 90-day reductions in Table 3. For this reason, my conservative assumption provides a likely lower bound estimate of the foregone emission reductions during the 90-day stay period, and in practice, the initial survey would likely help to secure much of the 60% annual reduction that EPA projects for well sites that comply with the LDAR requirements.

21. As described above, 18,231 wells that would otherwise have had to comply with LDAR requirements do not have to comply with those requirements during the stay. If none of these wells conduct LDAR, I estimate that additional emissions of 21,395 tons of methane, 5,899 tons of VOC, 225 tons of hazardous air pollutants will occur on an annual basis. As I explain above, this is a reasonable proxy for excess emissions that would result from a stay of the initial survey, as well as for annual emission reductions that would be lost if the 90-day stay is extended. If we instead adopt the conservative assumption that well sites leak at a constant rate, a lower bound estimate of excess emissions just during the 90-day stay period is 5,349 tons of methane, 1,475 tons of VOC, and 56 tons of hazardous air pollutants. As

[10] Comment of Clean Air Task Force *et al* on EPA's Proposed NSPS for the Oil and Natural Gas Sector, at Exhibits TA1-TA6, EPA Doc. Id No. EPA-HQ-OAR-2010-0505-7062. Relevant portions of the presentation are attached to this declaration as Exhibit B.

noted in paragraph 20, this lower bound estimate of excess emissions during the 90-day stay period likely understates the actual foregone emission reduction. Table 3 below summarizes the total number of affected sites, affected producing sites in states without separate state LDAR requirements, affected producing sites in ozone nonattainment areas, and affected low-producing sites along with additional emissions attributable to each of these categories.

Table 3: Summary of Affected Well Sources and Associated Emissions.

	# of Affected Wells	% of Affected Wells	Annual Emissions [tons]			90-day Emissions* [tons]		
			Methane	VOC	HAPs	Methane	VOC	HAPs
Total Sources	18,231	100%	21,395	5,899	225	5,349	1,475	56
Producing Wells in States with No LDAR Requirements	11,883	65%	17,204	4,742	181	4,301	1,185	45
Producing Wells in Ozone Non-attainment Area Counties	1,831	10%	3,013	832	32	753	208	8
Low-Producing Well Sources [based on NSPS definition]	2,179	12%	3,300	910	35	825	228	9

*Assumes a constant rate of reduction over the year which understates, perhaps significantly, the true foregone benefits of the initial survey, which reduces emissions substantially at the time of its completion.

22. Of the total wells that are subject to the NSPS and do not have to comply with the LDAR requirements during the stay, nearly 65%, or 11,883

producing wells, are located in states that do not have their own state regulations requiring LDAR.[11] These incremental sources will remain unregulated during the stay of the NSPS LDAR provisions, and I estimate that these sources will add 17,204 tons of methane emissions, 4,742 tons of VOC emissions, and 181 tons of hazardous air pollutant emissions into the air on an annual basis. A lower-bound estimate of excess emissions that will occur just during the 90-day stay period is 4,301 tons of methane, 1,185 tons of VOC, and 45 tons of hazardous air pollutants. As noted above, however, the LDAR requirements in the NSPS would also likely yield additional emission reductions even from affected wells that are already subject to state-level LDAR requirements.

Additional Ozone Forming Emissions Will Occur in Areas with Unhealthy Ozone Air Quality.

23. In ozone non-attainment areas, the incremental emissions during the stay from sources that would be covered by the NSPS LDAR requirements may have a particularly deleterious effect on local and regional ozone levels. There are 2,217 wells subject to the NSPS in counties that are currently not in attainment with the 2008 national ambient air quality standards for ozone. These sources will add an estimated 832 tons of VOCs to the atmosphere

[11] *See supra* ¶ 11.

during the stay of the LDAR requirements, which can contribute to the formation of additional ozone and exacerbating smog-related health issues. The timing of the stay results in these additional VOCs being released during peak ozone season summer months of June, July, and August during which VOCs and nitrogen oxides react with strong sunlight and heat.

Low Producing Wells Account for a Small Fraction of the Affected Facilities That Would Have Had to Comply with LDAR Requirements on June 3, 2017.

24. Although EPA has granted reconsideration specifically on the inclusion of low-production wells in the final NSPS, EPA's administrative stay goes far beyond these low-production wells to suspend fugitive emissions monitoring for all sources, including sources for which the agency is not reconsidering the standards. Low-production wells—which EPA defined in the proposed NSPS as wells that produce less than 15 barrels of oil equivalent per day—account for just 12% of total wells in the above dataset covered by the NSPS. The stay, however, sweeps broadly and includes both low and high-producing wells. The latter category, which is not subject to EPA's grant of reconsideration, accounts for the vast majority of wells and emissions. The 16,052 non-low production wells covered by the NSPS will emit an estimated 18,095 tons of methane, 4,989 tons of VOCs, and 190 tons of

hazardous air pollutants during the course of the 90-day stay, representing roughly 85% of the foregone methane reductions from all sources.

EPA Has Also Stayed LDAR Requirements for Compressor Stations, Which Are a Significant Source of Emissions but Not Subject to Any Grant of Reconsideration.

25. EPA has also stayed LDAR requirements for compressor stations, although it is not reconsidering the requirements applicable to those sources. Compressors are an important additional source of emissions, which I have estimated based on the number of affected sources and emissions reductions included in EPA's Technical Support Document. Table 4, below sets forth the results of this analysis.

Table 4: Summary of Compressor Station Emissions

	# of Affected Compressor Stations	Annual Emissions* [tons]			90-day Emissions** [tons]		
		Methane	VOC	HAPs	Methane	VOC	HAPs
Gathering and Boosting Compressor Stations	96	3,360	938	35	840	234	9
Transmission Compressor Stations	4	160	4	2	40	1	0.4
Storage Compressor Stations	5	710	20	7	178	5	2

* Emissions estimates are based on EPA Model Plant estimates in Tables 4-7 and 4-8 of the final TSD.
** Assumes a constant rate of reduction over the year which understates, perhaps significantly, the true foregone benefits of the initial survey, which reduces emissions substantially at the time of its completion.

Conclusion

26. EPA's stay will allow numerous sources to forego leak detection and repair requirements, allowing significant emissions to persist from these sources during both the 90-day stay period and beyond. The above analysis conservatively estimates the impacts of this stay, though the true impacts could be much greater and will swiftly grow over time as additional wells are drilled and completed without the need to meet standards to detect and remediate their leaking emissions.

I declare that the foregoing is true and correct.

David R. Lyon

David R. Lyon

Dated June 4, 2017

Exhibit G

PIONEER
NATURAL RESOURCES

November 25, 2019

Ms. Amy Hambrick
Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2017-0757
Mail Code 28221T
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Submitted electronically at: www.regulations.gov

Re: Pioneer Natural Resources' Comments to the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Review, 84 Fed. Reg. 50244 (September 24, 2019) Docket ID No. EPA-HQ-OAR-2017-0757

Dear Ms. Hambrick:

Pioneer Natural Resources USA, Inc. ("Pioneer" or "the Company") appreciates the opportunity to submit the following comments pursuant to the Environmental Protection Agency's ("EPA") Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Review proposed rule ("Policy Rule"). Pioneer intends these comments to provide valuable operator insight into this proposal.

Pioneer is a large independent oil and gas exploration and production company, headquartered in Dallas, Texas. The Company employs approximately 2,500 people and produces approximately 350,000 barrels of oil equivalent per day. Pioneer is a Permian pure-play company operating exclusively in the Midland Basin in West Texas. Pioneer's assets include the Sprayberry/ Wolfcamp Trend Areas where it is the largest operator.

Providing reliable access to affordable energy, while minimizing the environmental impact of carbon emissions, is one of the greatest challenges for the industry. Natural gas will continue to play a major role in meeting global energy demand. Since natural gas consists mainly of methane, a potent greenhouse gas ("GHG"), its part in the transition to a low carbon future will be influenced by the extent to which the oil and gas industry reduces its fugitive methane emissions. With appropriate measures to reduce methane leakage, natural gas provides an affordable, reliable, plentiful alternative to more carbon-intensive fuels. Already, increased use of natural gas in the United States and other countries has resulted in substantial GHG emissions reductions. However, voluntary actions and initiatives by only some companies in the oil and gas

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sector and a patchwork of inconsistent state regulations are insufficient to meet the challenge of significantly reducing methane emissions. For these reasons, Pioneer does not support EPA's Policy Rule proposal to rescind the methane-specific performance standards for the oil and gas sector.

Pioneer supports reasonable federal regulation of methane. A clear regulatory program would provide operators with certainty and predictability in their capital spending, strategic planning and operations. Sensible methane regulation that balances the value of oil and gas with environmental protection is necessary to elevate natural gas as a clean energy solution, thereby strategically positioning this valuable resource for growth and viability in the future.

The optimum result would be reasonable regulations that will incentivize early action, drive performance improvements, facilitate proper enforcement, support operational flexibility, and encourage technological innovation, particularly in the rapidly evolving area of methane leak detection, now and in the future. Pioneer strives to be an industry leader in minimizing emissions from operations and will continue to promote best practices, pilot innovative leak detection technologies, and seek out other voluntary ways to improve the Company's emissions footprint.

Pioneer appreciates the opportunity to comment on this rulemaking and EPA's consideration of this letter. Please contact me if you have any questions or require additional information.

Thank you,

Gretchen C Kern

Gretchen C. Kern
Sr. Environmental Policy Advisor
Sustainable Development
Email: Gretchen.Kern@pxd.com
Phone: 972.969.3936

Exhibit H

November 25, 2019

Ms. Amy Hambrick
Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2017-0757
Mail Code 28221T
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Submitted electronically at: www.regulations.gov

Re: Jonah Energy LLC Comments to the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Review, 84 Fed. Reg. 50244 (September 24, 2019) Docket ID No. EPA-HQ-OAR-2017-0757

Dear Ms. Hambrick:

Jonah Energy LLC (Jonah Energy) respectfully submits the following comments pursuant to the Environmental Protection Agency's Oil and Natural gas Sector: Emission Standards for New, Reconstructed and Modified Sources Review proposed rule.

Jonah Energy is a small independent oil and gas exploration and production company headquartered in Denver, Colorado. Our asset base is in Southwest Wyoming in the Jonah Field and surrounding area. We currently operate over 2,400 producing wells in the area and average approximately 550 mmcfe/day of gross production.

We work to reduce emissions and increase energy efficiency in both our planning and operations. In the Jonah Field, this includes nationally recognized programs to reduce air emissions, utilizing natural gas as a fuel source and virtually eliminating the practice of flaring. Natural gas fueled drill rigs, green completions and our leak detection and repair program are a few of the measures in place within the Jonah Field that have substantially reduced our operating emissions.

We currently exceed regulatory requirements with our monthly frequency of leak detection monitoring. We have implemented utilization of drones to supplement our handheld FLIR camera LDAR program and have begun pilot testing the use of fixed emissions monitors to determine if they can help us to further reduce our leak cycle time.

JONAH
ENERGY LLC

Jonah Energy strongly believes in the role of natural gas to meet current and future global energy demand and to provide reliable domestic energy and further believes this can be accomplished in an environmentally sensitive manner. Increased reliance on natural gas has already resulted in reductions of greenhouse gas emissions.

Jonah Energy supports reasonable federal regulations of methane emissions that provide consistency and certainty covering all sectors of natural gas development to promote public confidence in natural gas as a preferred energy source and provide operators with stability in their planning and capital spending. Regulations should incentivize operators who strive to improve using new technology, recognize and support different operations across the country and have a consistent enforcement mechanism.

Jonah Energy does not support EPA's Policy Rule proposal to recind the methane-specific performance standards for the oil and gas sector. The regulations are common sense, cost effective and help continue to reduce fugative methane emissions across the nation.

We appreciate the opportunity to comment. Please contact me if you require any additional information or have questions.

Sincerely,

Howard K Dieter

for Paul Ulrich
Vice President-Government and Regulatory Affairs
Jonah Energy LLC

Paul.ulrich@jonahenergy.com
303-330-6346

Exhibit I

November 25, 2019

Docket ID No. EPA–HQ–OAR–2017–0757
The Honorable Andrew Wheeler
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460
(submitted via regulations.gov)

Re: Proposed Rule – Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review

Dear Administrator Wheeler:

We appreciate the opportunity to comment on EPA's proposed rule, *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review* (Proposed Rule). As companies that purchase natural gas for delivery to customers and for use as a fuel source in electric power generation, we have significant concerns with EPA's proposal to remove regulation of methane emissions from the oil and natural gas source category. Federal regulation of methane emissions from the natural gas industry is important for ensuring methane emissions reductions industry-wide to address climate change and protect public health. Oil and gas operators have been complying with requirements to control methane emissions for several years, which demonstrates that compliance is being achieved using available technologies and strategies. We, therefore, respectfully request that EPA rescind the Proposed Rule and continue its regulation of methane.

Natural gas plays a critical role in the U.S. energy mix. As production methods and methane detection technologies have improved, North American natural gas has provided increasingly significant economic and environmental benefits to customers in the electric power, residential, industrial, and commercial sectors across the U.S. economy. At the same time, it is critical that the entire natural gas industry continue taking innovative, measurable, and economically viable steps to produce, transport, and use this resource as responsibly as possible to ensure its use remains consistent with the clean energy transition.

In response to interest from customers and investors, a range of voluntary initiatives related to methane emissions are underway throughout the natural gas supply chain. Through these voluntary initiatives, oil and natural gas companies are improving approaches to estimating, reporting, and reducing methane emissions from operations. These initiatives include developing new, innovative, and more effective technologies and processes for detecting and measuring fugitive methane emissions. Such efforts are important steps that complement and inform appropriate regulatory programs and reflect the fact that methane emissions are a key area of interest for customers, investors, and communities with natural gas operations as well as for other stakeholders—including our companies.

While voluntary efforts are important for reducing emissions and understanding how production operations can become more efficient and deliver environmental benefits, they cannot replace uniform federal methane regulations for the oil and natural gas industry. Federal methane regulations can ensure that the best system of emission reduction is deployed across the sector. With effective regulation, natural gas infrastructure can safely, reliably, and affordably deliver natural gas while controlling methane emissions.

In the Proposed Rule, EPA requests comment on an alternative interpretation of Clean Air Act (CAA) section 111. Previously, EPA has interpreted the section to provide it the discretion to determine which pollutants should be regulated within a source category that EPA has listed under section 111. Once EPA determines the source category contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare, the Agency has regulated emissions from that source category provided there is a reasonable and non-arbitrary basis. However, EPA is requesting comment on an alternative interpretation that would require the Agency to make a significant contribution finding each time it regulates a pollutant from an already listed source category. We support EPA's current interpretation of the section, which has been the foundation for regulating emissions under section 111 and agree with EPA's finding that it has a rational basis for concluding that methane emission from the oil and natural gas source category merit regulation under section 111. We do not agree that separate findings for each pollutant are required and would oppose any action that alters that determination.

Regulation of Methane from the Oil and Gas Source Category

EPA should continue to directly regulate methane from new sources in the oil and natural gas source category. Through compliance with the existing federal methane regulation, the industry has demonstrated that it can control methane emissions at a reasonable cost using available technologies and strategies. Companies throughout the natural gas supply chain are gaining experience with advanced methane detection technologies. We recognize the potential value many of these technologies could provide and support EPA looking for opportunities as part of ongoing and future methane regulatory efforts to recognize innovative alternative methane detection technologies that are demonstrated to be as effective as existing approaches.

The importance of controlling these emissions is clear when considering that the oil and natural gas source category is the largest source of anthropogenic methane emissions in the U.S., contributing 31 percent of U.S. methane emissions in 2017 according to EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017* (published in 2019).[1] Methane emissions have a higher global warming potential than carbon dioxide and are the second most significant greenhouse gas emitted from anthropogenic sources after carbon dioxide. Continued regulation of methane from the oil and natural gas source category is an important part of a strategy to reduce emissions that contribute to climate change.

In recent years, our companies have proactively reduced greenhouse gas emissions through investments in lower emitting generating resources, natural gas pipeline modernization, and implementation of best management practices. These initiatives reflect the expectations that our customers and investors have that the natural gas we use and deliver is produced, processed, and transmitted in a way that minimizes its environmental impacts. It is important for EPA to maintain the current requirements to deploy cost effective technologies that protect the environment and public health and to ensure a consistent regulatory framework.

Regulation of volatile organic compounds (VOC) emissions is not sufficient to control emissions from the oil and natural gas source category. VOC compositions can vary depending on the resource reservoir and the level of processing of the gas, resulting in different estimates of the cost effectiveness of control. Maintaining methane regulations for natural gas is not a redundancy, but a necessary method to control sources of air pollution.

[1] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2017 (April 2019) available at: https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017

EPA highlights in the Proposed Rule that states can and have implemented their own regulations to control air emissions from sources in the oil and natural gas source category. However, the structure of natural gas markets and the location of natural gas production basins is such that the gas our companies purchase, use, and deliver comes from a range of locations, frequently traveling hundreds of miles through pipelines to reach its destination. For example, EPA notes in the Proposed Rule that ten states, with 69 percent of natural gas production in 2018, have emission requirements for the oil and natural gas sector, but the sources regulated differ from state to state—creating a patchwork for the sector. Ten of the states regulate storage vessels and fugitive emissions at well sites, but only five regulate fugitive emissions at compressor stations, and only three directly regulate methane emissions. While we support state authority to implement their own requirements, especially in areas with air quality non-attainment concerns, federal regulation creates a consistent framework that establishes a minimum level of emission control that strengthens public confidence in the natural gas industry and ensures greenhouse gas emission reductions.

Regulation of Emissions from Transmission and Storage

In 2016, EPA conducted an analysis and concluded that there were cost effective strategies to reduce VOC and methane emissions from equipment associated with natural gas transmission and storage. EPA has not presented information in the Proposed Rule that supports a change in that conclusion. From our perspective, transmission and storage facilities are part of an integrated system that delivers natural gas to our systems and facilities. As such, we disagree with EPA's proposal to remove transmission and storage emission sources from the oil and natural gas source category. Rather, we support EPA's alternate proposal and historical definition of the source category—that transmission and storage sources are a part of the oil and natural gas source category. Consistent with the discussion above, we support retaining the methane standards as well as the VOC standards for transmission and storage sources.

Significant Contribution Finding for Methane

While the Proposed Rule retains EPA's interpretation of section 111 of the CAA related to the significant contribution and endangerment findings, EPA requests comment on whether section 111 should be interpreted to require EPA to make a pollutant-specific significant contribution finding for greenhouses gases as a prerequisite for regulating those emissions. We support EPA's current and historical interpretation of section 111 and would not support a change in this interpretation. If EPA were to change its current interpretation, the Agency would need to propose such a change as part of a separate rulemaking.

We see no ambiguity—the plain language of section 111(b) of the CAA directs EPA to make a determination of significant contribution when listing a source for regulation under section 111 and does not provide for such determination to be made when regulating other pollutants from that sector. As EPA explained in the 2016 NSPS OOOOa rule, section 111 makes clear that the significant contribution finding is made with respect to the source category, not a pollutant. Congress explicitly made this distinction when it did not include language in section 111 that requires EPA to make an endangerment finding for a particular pollutant as it did as part of other CAA provisions. For example, sections 211(c)(1) and 231(a)(2)(A) are specific for each pollutant. By contrast, section 111(b)(1)(A) is focused on EPA listing the source category, and section 111(b)(1)(B) directs EPA to propose and then promulgate regulations for new sources with each listed source category—not pollutant.

EPA has historically interpreted section 111 as granting the Agency the discretion to determine which pollutants should be regulated from the listed source category. In determining which pollutants are appropriate to regulate for a source category under section 111, EPA has relied on a rational basis for its decision.[2] This remains a reasonable approach as it ensures that the regulation of a pollutant from a listed source category is not arbitrary and capricious.

This limiting factor—the requirement of a rational basis to ensure the regulation of a pollutant from a source category is not arbitrary and capricious—ensures that EPA would not have the authority or basis to regulate an air pollutant from a source category that emits such pollutant in a small amount that is "relatively benign in its effect on public health or welfare." In this case, it would be arbitrary and capricious for EPA to decline to regulate greenhouse gas emissions from new, modified, and reconstructed oil and gas sources given that the source category is the largest source of anthropogenic methane emissions in the U.S., methane emissions are the second most significant greenhouse gas emissions in the U.S., the potential quantity of emissions from new sources, and the impacts of greenhouse gas emissions. Thus, EPA has a rational basis to regulate greenhouse gases from the oil and natural gas source category.

The Proposed Rule also requests comment on what the appropriate criteria would be if EPA were to make a pollutant-specific contribution finding. While we have noted that we do not agree that the language of the CAA supports such an exercise, the criteria EPA offers in the Proposed Rule for comment also raise concerns. First, projections of future emissions are inherently uncertain and are often subject to market dynamics, which are difficult to predict. Moreover, in the context of greenhouses gases, the accumulation of emissions in the atmosphere from new, modified, and existing sources of the source category as well as from other sources is a significant concern and must be considered.

For similar reasons, we would be concerned if EPA were to use the "simple percentage criterion that holds across pollutants and source categories" as described in the proposal for a significant contribution finding. Percent thresholds will shift over time for different sectors as some sectors reduce emissions cost-effectively more quickly and other sectors require time to develop effective reduction strategies. Additionally, we would oppose a single percentage applicable for all source categories as it is important to consider the impacts of the emissions and the nature of the emissions for each sector and pollutant separately. There could be sectors that are low contributors to emissions of a pollutant on an overall percentage basis that nonetheless have important environmental impacts.

According to the Proposed Rule, methane emissions are six percent of total U.S. greenhouse emissions when measured on a 100-year carbon dioxide equivalence basis. While methane emissions from the oil and natural gas sector are not the largest source of greenhouse gas emissions in the U.S., the share of the contribution from the sector may increase on a relative basis as other sectors, such as the electricity sector, reduce emissions. Moreover, methane has a higher global warming potential when measured over a shorter time period, increasing the importance of near-term emission reductions. Addressing these emissions is an important component of addressing climate change and its impacts. Therefore, EPA should retain the source-specific methane regulations for the oil and natural gas sector.

Conclusion

Addressing climate change will require reductions from a wide variety of sources across a range of sectors. As recognized by the Supreme Court in *Massachusetts v. EPA*, climate change is the result of emissions from numerous and diverse sources, "[a]gencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop"—which does not make an individual regulation irrelevant, rather it makes each individual

[2] *See, e.g.*, Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510, 64,530 (Oct. 23, 2015).

regulation an important component of an effective response.[3] Evaluating opportunities for emission reductions within each sector allows EPA to identify cost effective emission reduction strategies and to promote investment and innovation to further reduce emissions.[4] Companies have demonstrated that methane emissions can be regulated directly and cost effectively by successfully complying with the existing federal methane emission standards since they were finalized in 2016. Our companies support a comprehensive regulatory program for the oil and natural gas source category.

We appreciate the opportunity to comment on this Proposed Rule. If you have any questions about these comments, please do not hesitate to contact any of the signatory companies.

Sincerely,

Austin Energy
Calpine Corporation
Consolidated Edison Company of New York, Inc.
Exelon Corporation
Los Angeles Department of Water & Power
National Grid
NW Natural
Pacific Gas and Electric Company
Public Service Enterprise Group, Inc.
Tenaska, Inc.
Vermont Gas Systems

3 *Massachusetts v. EPA*, 549 U.S. 497 at 524 (2007).

4 42 U.S.C. § 7411(a)(1); *Sierra Club v. Costle*, 657 F.2d 298, 346 (D.C. Cir. 1981) ("Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and non-air quality health and environmental factors embraces consideration of technological innovation as part of that balance.").

Exhibit J

INTERFAITH CENTER ON CORPORATE RESPONSIBILITY
Inspired by faith, committed to action.

November 25th, 2019

Mr. Andrew Wheeler
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460
Submitted at http://www.regulations.gov

**Re: Comments on Proposed Rule: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review
Docket No. EPA-HQ-OAR-2017-0757-0002**

Dear Administrator Wheeler:

We appreciate the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's) proposed rule on reconsideration amendments for Standards for New, Reconstructed and Modified Sources in the Oil and Natural Gas Sector, also known as the New Source Performance Standards (NSPS).[1] As diversified, long-term investors with holdings in the U.S. oil and gas industry, we write to convey our opposition to EPA's proposal to rescind large portions of the currently effective NSPS regulations and urge you to maintain these regulations. These performance standards cover a range of existing and future oil and gas facilities across the country risks and are essential to ensure the health of our communities locally and globally.

We would like to highlight the strong opposition to the rule from the investor community at large. In late August 2019 we released an investor letter representing $5.51 trillion in assets under management that highlighted the serious concern regarding this rule.[2] Unprecedented support for the statement from both European and U.S. funds are a testament to the risks investors believe a regulatory rollback would represent to their portfolios. The investor statement, sent to 35 oil and gas companies laying out serious investor concerns about the regulatory rollback, is attached as part of this comment submission.

As shareholders, we have a vested interest in the long-term success of the companies in which we are invested. Measures to limit methane emissions are consistent with sound business practices and long-term company value. There is a viable role for natural gas within the transition to a low carbon economy. However, that role is dependent on mitigating methane emissions across the natural gas supply chain due to its potency as a hazardous greenhouse gas. This point is emphasized by the International Energy Agency, which has stated that "the potential for natural gas to play a credible role in the transition to a decarbonized energy system

[1] 84 Fed. Reg. 50,244 (September 24, 2019).
[2] Interfaith Center on Corporate Responsibility, *Citing Climate and Portfolio Risks, Investors Call on Oil and Gas Producers to Oppose Federal Methane Rollbacks*, Interfaith Center on Corporate Responsibility, 29 Aug. 2019, www.iccr.org/citing-climate-and-portfolio-risks-investors-call-oil-and-gas-producers-oppose-federal-methane.

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www.iccr.org

fundamentally depends on minimizing [methane] emissions."[3] Unrestricted methane emissions harm natural gas's long-term ability to compete with the rise of ever cheaper and cleaner forms of energy. Given the pervasive impacts of a warming climate, significant and "unhedgeable" risks are inherent in the threat of global warming. Reducing methane emissions now, from sources within the oil and gas industry, is an important step in countering these long-term risks to the global financial system.

While some companies are leading in the effort to reduce methane emissions, commonsense policies, like those EPA proposes to rescind, are needed to ensure all companies are tackling this problem on a level playing field. We oppose the EPA's argument that market incentives, existing voluntary programs, and state regulation of emissions from oil and gas sources will result in source pollution being controlled, as proactive operators belie the fragmented nature of the market where thousands of producers are not participating in programs to monitor and reduce their methane emissions. Additionally, we find that this proposal would prevent any future regulation of pollution from existing infrastructure, thus failing to reduce the most significant source of methane emissions from the industry. On the contrary, NSPS regulations would bring these non-participants into the fold, as estimates show that implementing the NSPS framework would cut supply chain methane leakage significantly by 40%.[4] Without nationwide methane regulation, the industry is only as strong as its weakest link.

EPA's own estimates of rescinding this regulation will result in 340,000 metric tons of unmitigated methane emissions while independent studies have shown that the net result will be 5 million metric tons of unmitigated methane emissions that would otherwise be prevented each year.[5] Far from damaging profitability, These unmitigated emissions represent a saleable resource that can generate positive economic returns. We speak regularly with oil and gas companies operating in the U.S., some of which are proactively tackling this issue and have continuously proven the cost-effectiveness of emission reduction measures that could and should be implemented by all in industry. Numerous methods of methane control have a net cost of zero or lower. Methods such leak detection and repair (LDAR) of sources of fugitive emissions, capturing vented gas and replacing high-bleed pneumatic devices with low-bleed pneumatics all represent abatement measures that can bring value to the natural gas supply chain while reducing its impact on the environment.

These regulations not only safeguard our environment but also our health. Roughly 17.6 million Americans live near active oil and gas operations and face serious health risks associated with fugitive emissions such as respiratory problems from increasing amounts of ozone in the atmosphere. In a report released in 2018, scientists who work for the EPA joined with other researchers to publish a peer-reviewed article estimating particulate matter related and ozone related health effects from the oil and natural gas industry as a whole.

[3] [3] Faith Birol, "World Energy Outlook Special Report: Energy and Climate Change." International Energy Agency. IEA, June 15, 2015, *available at:* https://www.iea.org/publications/freepublications/publication/WEO2015SpecialReportonEnergyandClimateChange.pdf

[4] Environmental Defense Fund. "EPA's Proposal to Rollback Methane Rules Ignores Scientific Evidence, Will Lead to 5 Million Tons of Methane Pollution." *Energy Exchange*, Environmental Defense Fund, 3 Sept. 2019, blogs.edf.org/energyexchange/2019/09/03/epas-proposal-to-rollback-methane-rules-ignores-scientific-evidence-will-lead-to-5-million-tons-of-methane-pollution/.

[5] Ibid.

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They predicted that these would account for 1,970 premature deaths, 39,000 individuals with upper and lower respiratory symptoms, 3,600 emergency room visits, and 1.1 million asthma attacks related to these emissions by 2025.[6] Furthermore, children are most at risk since they are more likely to spend time outdoors and their lungs are still developing. 1 in 10 children in the US have asthma and this is the number one reason for missing school. Children miss 500,000 days of school nationally due to oil and gas pollution.[7] Maintaining these regulations is not only the right choice for our environment, but also for the millions of Americans affected by these emissions.

Rescinding these crucial standards through the proposed rule would harm the climate, undermine public health, weaken our investment portfolios, and ultimately, hurt the economy. It will result in the waste of substantial volumes of saleable natural gas, and weaken the United States' financial and reputational position on the world stage—all measurable harms to investors in the sector. Given the damage that results from unmitigated oil and gas emissions and the readily available, low-cost opportunities to reduce them, methane standards are both necessary and warranted. As investors, we join the growing body of concerned stakeholders in opposition to this proposed rule and strongly urge the EPA to not adopt the proposed rule for the future security and sustainability of the US economy.

Respectfully submitted,

Christina Herman

Christina Herman
Program Director on Climate and Environment
Interfaith Center on Corporate Responsibility

[6] Fann, N., Baker, K.R., Chan, E.A.W., Eyth, A., Macpherson, A., Miller, E., Snyder, J. (2018) *Assessing Human Health PM2.5 and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025*. Environmental Science & Technology 52 (15), pp. 8095-8103. DOI: 10.1021/acs.est.8b02050

[7] Fleischmann, L., McCabe, D., Graham, J. (2016). *Gasping for breath: An analysis of the health effects from ozone pollution from the oil and gas industry*. Retrieved from http://www.catf.us/resources/publications/files/Gasping_for_Breath.pdf

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INVESTOR STATEMENT ON THE NEED FOR CONTINUED REGULATION OF METHANE IN THE OIL & GAS INDUSTRY

The undersigned investors, representing $5.51 trillion in assets under management, write with new and serious concerns regarding the Environmental Protection Agency's (EPA) proposed rollback of the New Source Performance Standards (NSPS) regulating oil and gas methane emissions. We believe that continued federal methane regulation is critical to the future of natural gas in the clean energy transition. We would like to hear the companies in our portfolios publicly support continued federal regulation of methane and oppose EPA's proposed rollback.

The EPA's proposed rollback of methane regulations comes at a landmark time for the U.S. oil and gas industry, presenting a risk to recent economic gains. As U.S. production reaches record highs and the U.S. oil and gas industry experiences strong export growth, methane standards support global competitiveness in a world with shrinking carbon budgets and growing international climate policy action. Furthermore, methane mitigation technologies have proven themselves cost-effective when implemented, driving additional revenue through the capture of lost product.

The rollback of existing, strong, yet cost effective, regulatory standards will lead to policy uncertainty for industry for years to come. Further, a decision by the EPA to stop considering the oil and gas industry a significant source of harmful methane emissions could increase legal uncertainty over the status of the rollback itself. Finally, if the proposed rollback is enacted without opposition from those in industry, the deregulation of methane and the acquiescence of the industry will shape the public narrative on natural gas, overshadowing proactive measures of industry leaders.

Some companies are demonstrating leadership on managing methane emissions—both by reducing their own emissions and by advocating for continued federal regulation of methane.[1, 2, 3, 4] Yet industry performance is not uniform, and others remain largely inactive. The result is a fragmented market with mixed performance on emissions reductions. Ultimately, the removal of methane regulations deepens the threat from climate change, increasing economy-wide risks. Methane rules are the most effective tool to ensure a level playing field and to protect the industry as a whole from these material risks.

Therefore, we ask you to engage proactively during the ongoing rulemaking process by:

- Submitting comments to the EPA expressing:
    - support of the direct regulation of methane and its significance for the oil and gas industry
    - the importance of upholding the scientific consensus and maintaining the EPA's finding that methane from oil and gas sector sources contributes to GHG pollution and climate change
- Urging your trade associations and industry groups to support direct regulation of methane and affirm the scientific consensus on methane emissions from the oil and gas industry

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[1] **Shell**: https://www.linkedin.com/pulse/shell-supports-direct-regulation-methane-heres-why-gretchen-watkins/
[2] **BP**: https://www.houstonchronicle.com/opinion/editorials/article/BP-America-chief-It-s-time-for-the-Trump-13721656.php
[3] **Exxon**: https://www.forbes.com/sites/edfenergyexchange/2019/03/12/edf-and-exxonmobil-discuss-technology-and-regulation-to-reduce-methane-emissions/#50f8a5614d9e
[4] **Equinor**: https://www.equinor.com/en/how-and-why/climate-change/methane.html

Elimination of the direct regulation of methane emissions will drive volatility and uncertainty. The rollback of federal regulation will lead to excessive methane emissions, threatening the role of natural gas in the low carbon future and challenging oil and gas companies' social license to operate. The need for comprehensive national standards to mitigate sector-wide risk is clear. Industry silence will be interpreted as implicit support for no regulation at all.

In order to protect the natural gas industry's future global competitiveness, we urge you to publicly support continued EPA regulation of methane emissions.

Investor Signatories:

Aargauische Pensionskasse (APK), Switzerland
Adrian Dominican Sisters, Portfolio Advisory Board
Aegon Asset Management
Allianz Global Investors
As You Sow
Bernische Lehrerversicherungskasse, Switzerland
Bernische Pensionskasse BPK, Switzerland
Bon Secours Mercy Health
Boston Common Asset Management, LLC
Caisse de pension des sociétés Hewlett-Packard en Suisse, Switzerland
Caisse de pensions de l'Etat de Vaud (CPEV), Switzerland
Caisse de pensions ECA-RP, Switzerland
Caisse de prév. des Fonctionnaires de Police & des Etablissements Pénitentiaires, Switzerland
Caisse de Prévoyance de l'Etat de Genève (CPEG), Switzerland
Caisse de Prévoyance des Interprètes de Conférence (CPIC), Switzerland
Caisse de prévoyance du personnel de l'Etat du Valais (CPVAL), Switzerland
Caisse intercommunale de pensions (CIP), Switzerland
Caisse paritaire de prévoyance de l'industrie et de la construction (CPPIC), Switzerland
California State Teachers' Retirement System (CalSTRS)
CANDRIAM
CAP Prévoyance, Switzerland
Catholic Health Initiatives
CCAP Caisse Cantonale d'Assurance Populaire, Switzerland
CCLA
Christian Brothers Investment Services (CBIS)
Church Commissioners for England
Church Investment Group
Church of England Pensions Board
CIEPP - Caisse Inter-Entreprises de Prévoyance Professionnelle, Switzerland
Clean Energy Ventures
Committee on Mission Responsibility Through Investment of the Presbyterian Church U.S.A.
Conference for Corporate Responsibility Indiana and Michigan

Congregation of Sisters of St. Agnes
Congregation of St. Joseph
Dana Investment Advisors
Daughters of Charity, Province of St. Louise
Dignity Health
Domini Impact Investments LLC
Dominican Sisters of San Rafael
Dominican Sisters of Sparkill
ERAFP
Etablissement Cantonal d'Assurance (ECA VAUD), Switzerland
Ethos Foundation, Switzerland
Figure 8 Investment Strategies
First Affirmative Financial Network
Fondation de la métallurgie vaudoise du bâtiment (FMVB), Switzerland
Fondation de prévoyance Artes & Comoedia, Switzerland
Fondation de prévoyance du Groupe BNP PARIBAS en Suisse, Switzerland
Fondation Leenaards, Switzerland
Fonds de Prévoyance de CA Indosuez (Suisse) SA, Switzerland
Friends Fiduciary Corporation
FSPA
Harvard University Endowment
Hermes EOS
Hermes Investment Management
Impacts Investors
Impax Asset Management
ICCR (Interfaith Center on Corporate Responsibility)
Ircantec
Jantz Management LLC
Jesuits of the US Central and Southern Province
JLens Investor Network
Jupiter Asset Management
LAPFF (the Local Authority Pension Fund Forum)
Leadership Team - Felician Sisters of North America
Legal & General Investment Management
Macroclimate LLC
Manulife Investment Management
Maryknoll Sisters
Maryland Province of the Society of Jesus
Mercy Investment Services, Inc.
Miller/Howard Investments, Inc.
MN
Natural Investments

NEI Investments
Nest Sammelstiftung, Switzerland
New York City Comptroller's Office
Newground Social Investment
NorthStar Asset Management, Inc.
Northwest Coalition for Responsible Investment
Ostrum
Pax World Funds
Pensionskasse Basel-Stadt, Switzerland
Pensionskasse Bühler AG Uzwil, Switzerland
Pensionskasse Caritas, Switzerland
Pensionskasse der Stadt Winterthur, Switzerland
Pensionskasse Pro Infirmis, Switzerland
Pensionskasse Römisch-katholische Landeskirche des Kantons Luzern, Switzerland
Pensionskasse SRG SSR, Switzerland
Pensionskasse Stadt Luzern, Switzerland
Pensionskasse Unia, Switzerland
Prévoyance Santé Valais (PRESV), Switzerland
prévoyance.ne, Switzerland
Profelia Fondation de prévoyance, Switzerland
Prosperita Stiftung für die berufliche Vorsorge, Switzerland
Providence St. Joseph Health
Rathbone Brothers Plc
Region VI Coalition for Responsible Investment
Religious of the Sacred Heart of Mary WAP
Retraites Populaires, Switzerland
Riverwater Partners
RLAM
Robeco
Sarasin & Partners LLP
School Sisters of Notre Dame Cooperative Investment Fund
Secunda Sammelstiftung, Switzerland
Seventh Generation Interfaith Inc.
SHARE (Shareholder Association for Research & Education)
SharePower Responsible Investing
Sisters for Notre Dame de Namur Base Communities
Sisters of Charity of Nazareth
Sisters of Mary Reparatrix
Sisters of Saint Joseph of Chestnut Hill, Philadelphia, PA
Sisters of St. Dominic of Caldwell, NJ
Sisters of St. Dominic/Racine Dominicans
Sisters of St. Francis of Philadelphia

Sisters of St. Joseph of Orange
Sisters of the Holy Cross
Sisters of the Humility of Mary
Sisters of the Presentation of the BVM of Aberdeen SD
Skye Advisors LLC
Socially Responsible Investment Coalition
St. Galler Pensionskasse, Switzerland
Stiftung Abendrot, Switzerland
Storebrand Asset Management
Terre des hommes, Switzerland
The Episcopal Church (DFMS)
The Province of Saint Joseph of the Capuchin Order
The Sustainability Group of Loring, Wolcott & Coolidge
Tri-State Coalition for Responsible Investment
Trillium Asset Management
Trinity Health
Unitarian Universalist Association
Université de Genève (UNIGE), Switzerland
USA Midwest Province Jesuits
USA Northeast Province of the Society of Jesus
USA West Province of the Society of Jesus
Walden Asset Management/ Boston Trust
Wespath Benefits and Investments
Wetherby Asset Management

Exhibit K

Comments to US EPA on the Proposed Rule for the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review

Catherine Hausman
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Daniel Raimi[1]
Senior Research Associate
Resources for the Future
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raimi@rff.org

October 16, 2019

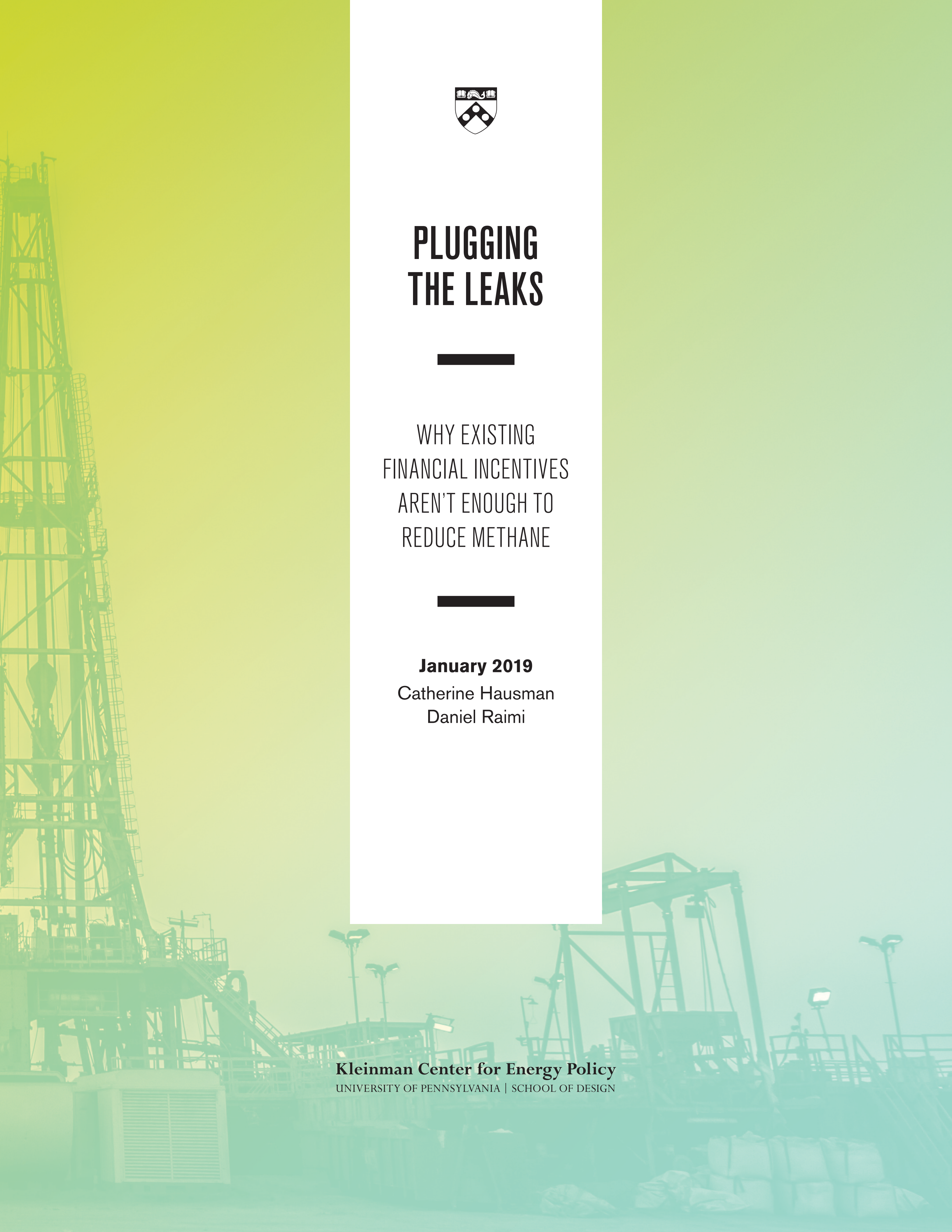
Attention: Docket ID No. EPA-HQ-OAR-2017-0757

Please find attached our report, "Plugging the Leaks: Why Existing Financial Incentives Aren't Enough to Reduce Methane," published by the Kleinman Center for Energy Policy at the University of Pennsylvania.

Our report speaks directly to the claims made in the proposed rule, that "As methane is the primary constituent of natural gas, an important commodity, operators have market incentives to reduce emissions and the loss of valuable product to the atmosphere. Absent regulation, the incentive to maximize the capture of natural gas is the market price obtained by the operator producing the natural gas. Assuming financially rational-acting producers, standard economic theory suggests that oil and natural gas operators will incorporate all cost-effective production improvements of which they are aware without government intervention" (Federal Register, Vol 84, No 185, page 50274). Note that similar claims are made on pages 50249 and 50271.

As we describe in depth in the attached report, this claim is erroneous in that it ignores a basic principle of economics: if there is an externality associated with methane emissions, then private actors will reduce emissions at a rate that is less than optimal for society as a whole. This is precisely why the Environmental Protection Agency develops and enforces regulations that protect human health and the environment.

[1] Affiliations are provided for identification purposes. These views represent those of Hausman and Raimi, not the University of Michigan nor Resources for the Future.



PLUGGING THE LEAKS

WHY EXISTING FINANCIAL INCENTIVES AREN'T ENOUGH TO REDUCE METHANE

January 2019

Catherine Hausman
Daniel Raimi

Kleinman Center for Energy Policy
UNIVERSITY OF PENNSYLVANIA | SCHOOL OF DESIGN

PLUGGING THE LEAKS

WHY EXISTING FINANCIAL INCENTIVES AREN'T ENOUGH TO REDUCE METHANE

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THE PROBLEM

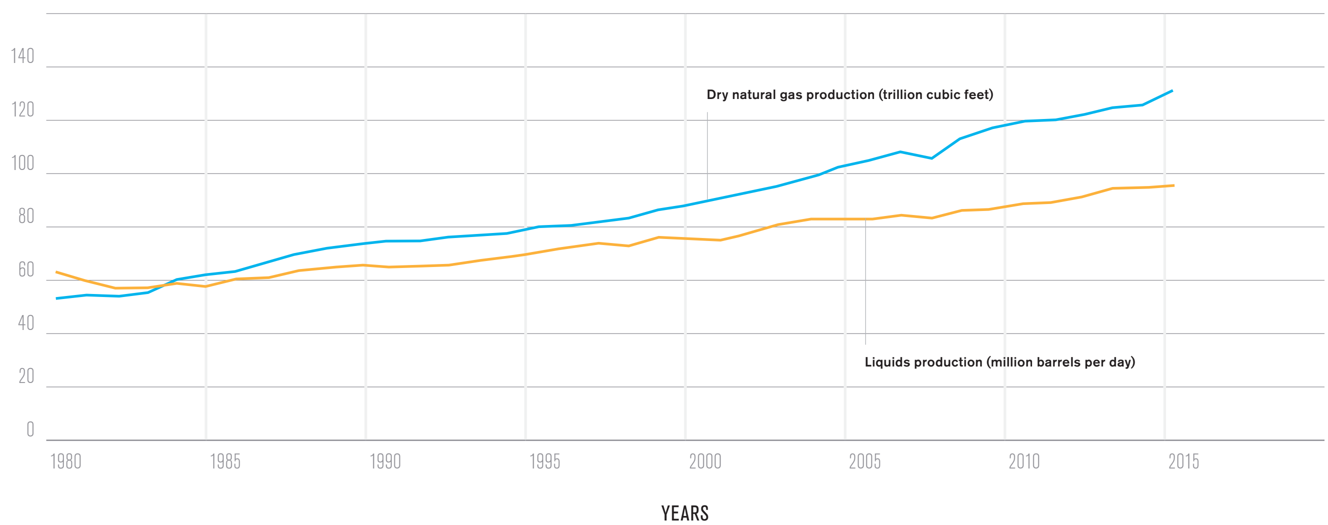
Methane is a significant contributor to global climate change, representing 16 to 20% of total greenhouse gas emissions, on a CO_2-equivalent basis, in 2010 (Intergovernmental Panel on Climate Change 2014a). While multiple sectors emit methane, a major contributor is the production and use of fossil fuels, particularly the oil and gas industry (U.S. Environmental Protection Agency 2012). With global oil and gas production growing (Figure 1), understanding the scientific and market forces surrounding these emissions is a crucial component of climate policy.

Global estimates of oil and gas methane emissions are highly uncertain (an important issue that we will explore), but one recent study estimated that 3.6 trillion cubic feet of methane were emitted by global oil and gas systems in 2012 (Larsen, Delgado, and Marsters 2015). At current estimates of the monetary cost of climate change impacts (discussed in detail below), these emissions caused roughly \$75 to \$100 billion in global damages.[1]

Although companies would, in most cases, prefer not to waste methane, leaks are commonplace because—from a company's perspective—they are not always cost-effective to prevent or to fix once they occur.

Scientists and environmental advocates are increasingly calling attention to the methane problem, and some jurisdictions have responded with new policy. At the

FIGURE 1: GLOBAL OIL AND NATURAL GAS PRODUCTION



Source: U.S. Energy Information Administration

1 This calculation uses the social cost of methane of \$1,300 to \$1,600 per metric ton (U.S. Environmental Protection Agency 2018c, p. A-8); and the conversion between tons of CH4 and cubic feet of natural gas in Brandt et al. (2014).

U.S. federal level, the Obama administration developed initiatives through the Bureau of Land Management (BLM) and the Environmental Protection Agency (EPA); California, Colorado, Pennsylvania, Wyoming, and others have proposed state-level rules; the Global Methane Initiative is a multilateral initiative across dozens of countries; and the One Future Initiative brings together leading energy companies to reduce methane emissions. However, the Trump administration has walked back some Obama-era rules, and as of this writing, the EPA is accepting comments on a proposed rollback of its earlier regulations (U.S. Environmental Protection Agency 2018d).

In this policy brief, we summarize the best available evidence on oil- and gas-related methane emissions in the U.S. and the damages they cause. We then describe the market forces shaping methane leaks and their abatement. We conclude by drawing lessons for policymakers.

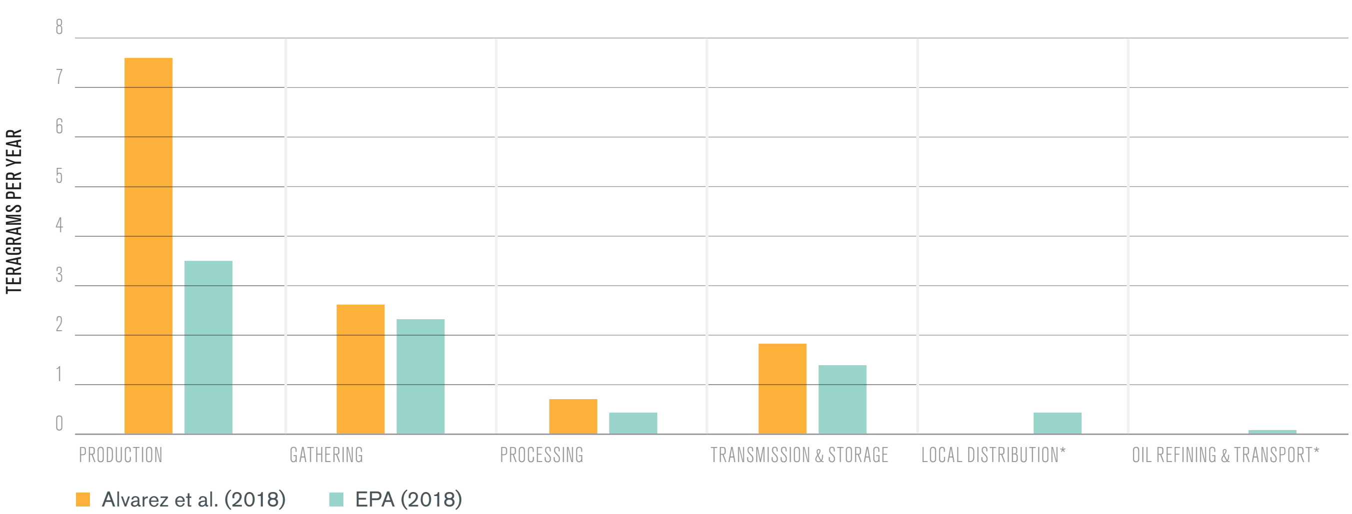
THE SCIENCE OF METHANE LEAKS

Around one third of U.S. anthropogenic methane emissions are from the oil and gas sector (other major contributors are livestock, manure, landfills, and coal mines). The reason is simple: the primary component of natural gas is methane, and gas leaks occur throughout the supply chain. Moreover, since most oil wells also produce natural gas, extraction of oil can increase methane emissions.

Leaks can occur at all stages of the supply chain, including production, processing, long distance transmission, and local distribution. Some leaks occur when underground pipelines corrode; others occur at surface equipment; and still others occur when gas is intentionally vented during maintenance tasks. Detecting and measuring leaks is hard, since methane itself is odorless and colorless—the "rotten egg" smell most people associate with natural gas is due to an odorant added to help make it detectable.

Measuring methane emissions has been a key focus of recent research. Scholars have published dozens of studies examining emissions from specific pieces of oil and gas production equipment (e.g., Allen et al. 2013, 2015), processing equipment (e.g., C. W. Moore et al. 2014; Marchese et al. 2015; Mitchell et al. 2015), and transportation infrastructure (e.g., Phillips et al. 2013; Jackson et al. 2014; Gallagher et al. 2015), as well as collecting "top-down" measurements of methane emissions across broad regions (e.g., Karion et al. 2013, 2015; Kort et al. 2016; Barkley et al. 2017).

FIGURE 2: METHANE EMISSIONS FROM A RECENT META-ANALYSIS AND EPA



*Not estimated by Alvarez et al. (2018)

Source: Alvarez et al. (2018) and U.S. EPA (2018a)

A recent meta-analysis of many of these studies estimated that roughly 2.3% of natural gas production in the United States is emitted as methane (Alvarez et al. 2018), about 60% higher than the most recent estimates from the U.S. Environmental Protection Agency (U.S. Environmental Protection Agency 2018a). This revised estimate is likely more accurate because it is based on a set of measurements that are both more recent and more comprehensive than the existing EPA estimates.

As Figure 2 shows, the meta-analysis found substantially higher emissions than EPA estimates: 117% higher during production, 13% higher during gathering, 64% higher during processing, and 29% higher during transmission and storage. And while the meta-analysis did not update emissions from the distribution sector nor from "behind-the-meter" uses like home furnaces or water heaters, other work suggests that the EPA's estimates may be too low at those stages of the supply chain as well (Phillips et al. 2013; Jackson et al. 2014; Alvarez et al. 2018).

As that methane accumulates in the atmosphere, it traps heat, contributing to global warming. And although methane's effects on the climate are not nearly as long lasting as carbon dioxide, methane—on a pound for pound basis—traps more than 80 times as much heat in the atmosphere as CO_2 over a 20-year timeframe, and more than 30 times as much over 100 years (U.S. Environmental Protection Agency 2018b).

Climate-related damages from methane have been estimated at $1,300 to $1,600 per ton (U.S. Environmental Protection Agency 2018c, p. A-8). Those estimates were part of a major U.S. government initiative by policymakers and academics to quantify the risks to society from climate change (Interagency Working Group on the Social Cost of Carbon 2010, 2013, 2016). Recent peer-reviewed studies have estimated even higher damages from climate change (e.g., Pindyck 2017; F. C. Moore et al. 2017; Ricke et al. 2018), though substantial uncertainty remains.

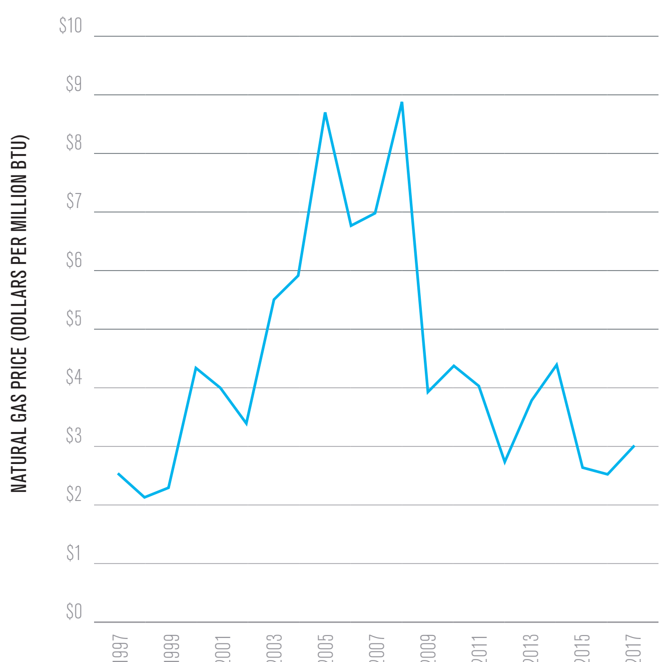
In addition to the climate risks, methane leaks can pose a public safety hazard. While methane itself has no direct impact on human health at most concentrations, natural gas leaks frequently include other gases that are toxic and/or contribute to ground-level ozone (smog) (Carter and Seinfeld 2012; McMullin et al. 2018; Fann et al. 2018). And in rare cases, leaking natural gas can cause explosions—and indeed, fatalities have occurred because of explosions from transmission lines (Bowe and Pickoff-White 2015), distribution lines (McEvoy 2013), and gathering lines (Elliot 2017; Soraghan and Lee 2018).

THE ECONOMICS OF METHANE LEAKS

Companies that produce, process, and transport natural gas and oil often argue (e.g., Henry 2016; Silverstein 2018) that they have an economic incentive to reduce methane emissions and market the captured gas as a product.

According to economic theory, companies will capture methane emissions if the economic costs of doing so are less than the value of the lost gas. In fact, the revenue that private companies stand to gain from capturing each unit of methane has been relatively low in recent years, as increased domestic natural gas production has lowered benchmark prices (Figure 3) to an annual average of $2.70 per million British thermal units (MMBtu) for 2015–2017 (U.S. Energy Information Administration 2018).

FIGURE 3: U.S. NATURAL GAS PRICES (HENRY HUB SPOT PRICE)



Source: U.S. Energy Information Administration. Nominal dollars.

More importantly, the company's argument about their desire to avoid lost product is only partially correct: while there is some economic incentive to prevent leaks, it is not at the full, socially-optimal level. A simple rule of thumb from the field of economics tells us that government regulation is needed to address the methane issue. That rule is as follows: if there is an externality associated with methane emissions, then private actors will reduce emissions at a rate that is less than optimal for society as a whole.

From society's perspective, the damage caused by each additional MMBtu of methane emissions ranges from $2.80 to $27 *in addition* to the value of the lost gas. This number ranges widely because there are a number of important assumptions that affect the social cost of methane.

EPA states that, using a domestic-only social cost of methane—which is preferred by the Trump Administration, and which only accounts for the impacts of global warming directly affecting the United States—and a discount rate of 3%, each metric ton of methane emissions results in $170 to $200 worth of damages to society, roughly equivalent to $2.80–3.30/MMBtu.[2]

However, leading economists have argued for the application of a *global* social cost of methane—that is, accounting for the global damages of climate change, rather than only those directly experienced in the United States—under which the damages to society from each metric ton of methane emissions are roughly $1,300 to $1,600—equivalent to $22 to $27/MMBtu (U.S. Environmental Protection Agency 2018c, p. A-8).[3] Moreover, these estimates do not reflect advances in the scientific understanding of methane's atmospheric and radiative efficacy, which are expected to increase the cost estimates for methane (U.S. Environmental Protection Agency 2018c, p. 3–12).

It's worth noting that these global damages reflect real economic risks to the United States, as climate change will impact the global economy (Intergovernmental Panel on Climate Change 2014b; Burke, Hsiang, and Miguel 2015; Burke, Davis, and Diffenbaugh 2018), with which the U.S. economy is well-integrated. In addition, climate change poses risks for increased civil conflict (Burke et al. 2010; Hsiang, Meng, and Cane 2011), with implications for U.S. security and the economy.

TABLE 1: PRIVATE VERSUS SOCIAL BENEFITS OF METHANE LEAK REDUCTIONS

Category	Beneficiary	Magnitude	Examples
Market Value of Natural Gas	Company	$2.70/MMBtu	Marketable Product (used for heating, cooking, etc.)
Climate	U.S. and Global Populations	$22–27/MMBtu	Rising Temperatures Sea Level Rise Extreme Events (wildfires, increased hurricane intensity, etc.) Loss of Ecosystems
Health and Safety	Local Populations	Unknown >$0/MMBtu	Explosion Risk Air Quality (associated gas contributing to smog)

2 Page 3 to 9 of the EPA's Regulatory Impact Assessment (RIA) for the Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources (U.S. Environmental Protection Agency 2018b). For this conversion from metric tons of methane to MMBtu, we use the conversion factors in Brandt et al. (2014) and the conversion of 1 MMBtu per 1.028 Mcf from EPA (U.S. Environmental Protection Agency 2018c).

3 A global social cost of greenhouse gases and a discount rate of 3% are consistent with methods and models used by federal agencies, in line with the best available peer-reviewed scientific and economic studies, and upheld by the courts, as testified by Michael Greenstone to the United States House Committee on Science, Space and Technology, February 28, 2017 (Greenstone 2017).

Stepping back, then, it becomes clear what is missing from companies' claims that their financial incentives are properly aligned to detect and abate leaks. Suppose a leak repair technology costs $10 per MMBtu of gas captured. A private company will not implement that technology, since it costs more than the potential revenue of the captured gas ($2.70). At the same time, society as a whole would very much like the company to implement the technology, since it avoids $22 to $27 per MMBtu of climate damages such as hurricane and wildfire risk, plus the other safety and health risks described at left.

POLICY IMPLICATIONS

This simple exercise provides a powerful lesson: government regulation to reduce methane emissions can benefit society. This is true under any market condition, since a company can only capture the private benefits of captured methane, whereas society as a whole—not just the company—bears the damages associated with climate risks. Moreover, this idea points to the weakness inherent in voluntary targets set by companies—they do not come with the financial incentive that guarantees sufficient emissions abatement.

In the presence of this externality, companies will fail to capture methane emissions when the cost is above $2.70/MMBtu, regardless of the full social value of captured emissions ($2.70/MMBtu plus $22 to $27/MMBtu of climate risks, plus additional health and safety risks). Government regulations are thus needed to induce methane capture, and recent studies show that there are many opportunities for low-cost abatement (ICF International 2014). Those regulations should be designed to capture the "low hanging fruit," achieving the greatest possible reductions for the lowest possible costs.

A challenge going forward is that we do not yet have comprehensive methane monitoring, implying that some regulatory options (such as an emissions tax that includes methane leaks) are not currently feasible.

One option, a flat tax on production, processing, and transport would not be equivalent—it would equally punish gas *sold* and gas *leaked*, which would not properly incentivize leak capture. At the same time, more extreme policy measures, such as fracking bans, would imply that a valuable product would not be available to consumers. Our own research suggests that the climate damages are not currently large enough to justify a ban on fracking (Hausman and Kellogg 2015; Raimi 2017). In fact, under some conditions, the increased use of natural gas can help reduce greenhouse gas emissions in the short term, by allowing for a more rapid transition away from coal (Newell and Raimi 2014; Raimi 2017).

The options left on the table, then, are regulations on the way that natural gas and oil are extracted, processed and transported. That is exactly what the Obama administration's rules were intended to target—rules that the Trump administration would like to roll back.

Additional regulatory options may be appropriate at the distribution stage. For example, many distribution companies are price-regulated by state utility commissions. Under this structure, the companies are typically reimbursed for the value of their leaked gas, reducing or eliminating their financial incentive to plug leaks. California has taken steps forward in this domain (California Public Utilities Commission 2018), and other policy options are briefly described in Hausman and Muehlenbachs (2018) and Costello (2013).

Moreover, new technologies are emerging that will allow companies throughout the supply chain to more easily identify so-called "super-emitters," the small number of sites that account for a large proportion of emissions (Brandt, Heath, and Cooley 2016; Mayfield, Robinson, and Cohon 2017). These technologies may continue to improve over time, allowing for lower-cost abatement opportunities moving forward. Regulations could take advantage of, and perhaps even incentivize, these and other emerging leak detection and repair technologies.

In short, market forces will not solve the problem of methane leaks. While companies have an incentive to capture the escaping gas, that incentive is well below the levels which would be best for society as a whole. As technologies for detecting and measuring methane emissions become cheaper, the private incentive to capture more methane may increase. But Economics 101 tells us that in the presence of an externality like this one, there is a clear justification for government action.

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